PB-245 162

PROGRAM FOR REDUCTION OF NOx FROM TANGENTIAL COAL-FIRED BOILERS. PHASE II

Ambrose P. Selker

Combustion Engineering, Incorporated

Prepared for:

National Environmental Research Center

June 1975

DISTRIBUTED BY:

NTIS

National Technical Information Service
U. S. DEPARTMENT OF COMMERCE

276056

PB 245 162

EPA-650/2-73-005-a

June 1975

Environmental Protection Technology Series

PROGRAM FOR REDUCTION OF NO_x FROM TANGENTIAL COAL-FIRED BOILERS PHASE II

Reproduced by
NATIONAL TECHNICAL
INFORMATION SERVICE
US Department of Commerce
Springfield, VA. 22151

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-650/2-73-005-a	2.
3. RECIPIENT'S ACCESSION NO.	
4. TITLE AND SUBTITLE: Program for Reduction of NOx from Tangential Coal-Fired Boilers, Phase II	5. REPORT DATE: June 1975
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S): Ambrose P. Selker	8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS: Combustion Engineering, Inc., 1000 Prospect Hill Road, Windsor, Connecticut 06095	10. PROGRAM ELEMENT NO. 1AB014; ROAP 21ADG-080
	11. CONTRACT/GRANT NO. 68-02-1367
12. SPONSORING AGENCY NAME AND ADDRESS: EPA, Office of Research and Development, NERC-RTP, Control Systems Laboratory, Research Triangle Park, NC 27711	13. TYPE OF REPORT AND PERIOD COVERED: Phase II Final; 7/73 - 3/75
	14. SPONSORING AGENCY CODE
15. SUPPLEMENTARY NOTES	

16. ABSTRACT: The report gives results of Phase II of a program to reduce the emission of NOx from tangential coal-fired boilers. Results of Phase I, during which a suitable utility steam generator was selected to be modified for the Phase II studies, were presented in final report EPA-650/2-73-005, dated August 1973. The Phase II work included: the design, fabrication, and delivery of an overfire air system for the test unit; the installation of test equipment; planning; and baseline, biased firing and overfire air studies for NOx emission control while burning a Kentucky bituminous coal type. These test programs included an evaluation of the effect of variations in excess air, unit slagging, load, and overfire air on unit performance and emission levels. The effect of biasing combustion air through various out-of-service fuel nozzle elevations was also evaluated. The effect of biased firing and overfire air operation on waterwall corrosion potential was evaluated during three 30-day baseline, biased firing, and overfire air corrosion coupon tests. Unit loading and waterwall slag conditions had minimal effects on NOx emission levels. Reductions in excess air levels and overfire air operation were found to be effective in reducing NOx emission levels.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Air Pollution Control	13B
Nitrogen Oxides	Stationary Sources	07B
Combustion Control	NOx Reduction	21B
Coal	Tangential Firing	21D
Boilers	Combustion Modification	13A

18. DISTRIBUTION STATEMENT: Unlimited	19. SECURITY CLASS *(This Report)*: Unclassified	21. NO. OF PAGES: 144
	20. SECURITY CLASS *(This page)*: Unclassified	22. PRICE: 5.75

EPA Form 2220-1 (9-73)

EPA-650/2-73-005-a

PROGRAM FOR REDUCTION OF NO_X FROM TANGENTIAL COAL-FIRED BOILERS PHASE II

by

Ambrose P. Selker

Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, Connecticut 06095

Contract No. 68-02-1367
ROAP No. 21ADG-080
Program Element No. 1AB014

EPA Project Officer: David G. Lachapelle

Control Systems Laboratory
National Environmental Research Center
Research Triangle Park, North Carolina 27711

Prepared for

U. S. ENVIRONMENTAL PROTECTION AGENCY
OFFICE OF RESEARCH AND DEVELOPMENT
WASHINGTON, D. C. 20460

June 1975

EPA REVIEW NOTICE

This report has been reviewed by the National Environmental Research Center - Research Triangle Park, Office of Research and Development, EPA, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Environmental Protection Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into series. These broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and maximum interface in related fields. These series are:

1. ENVIRONMENTAL HEALTH EFFECTS RESEARCH
2. ENVIRONMENTAL PROTECTION TECHNOLOGY
3. ECOLOGICAL RESEARCH
4. ENVIRONMENTAL MONITORING
5. SOCIOECONOMIC ENVIRONMENTAL STUDIES
6. SCIENTIFIC AND TECHNICAL ASSESSMENT REPORTS
9. MISCELLANEOUS

This report has been assigned to the ENVIRONMENTAL PROTECTION TECHNOLOGY series. This series describes research performed to develop and demonstrate instrumentation, equipment and methodology to repair or prevent environmental degradation from point and non-point sources of pollution. This work provides the new or improved technology required for the control and treatment of pollution sources to meet environmental quality standards.

This document is available to the public for sale through the National Technical Information Service, Springfield, Virginia 22161.

Publication No. EPA-650/2-73-005-a

ABSTRACT

This report presents the findings of the Phase II "Program For Reduction of NO_x From Tangentially Coal Fired Boilers" performed under the sponsorship of the Office of Research and Development of the Environmental Protection Agency (Contract 68-02-1367). Phase I of the program consisted of selecting the Alabama Power Company, Barry Station #2 steam generator which was modified for the studies performed under Phase II. The Phase I results were presented in final report EPA-650/2-73-005, dated August, 1973.

The work accomplished under Phase II included the design, fabrication, and delivery of an overfire air system for the test unit, the installation of test equipment, planning, and the conducting of baseline, biased firing and overfire air studies for NO_x emission control while burning a Kentucky bituminous coal type.

These test programs included an evaluation of the effect of variations in excess air, unit slagging, load and overfire air on unit performance and emission levels. Additionally, the effect of biasing combustion air through various out of service fuel nozzle elevations was also evaluated. The effect of biased firing and overfire air operation on waterwall corrosion potential was evaluated during three thirty (30) day baseline, biased firing and overfire air corrosion coupon tests.

Unit loading and waterwall slag conditions exhibited minimal effects on NO_x emission levels while reductions in excess air levels and overfire air operation were found to be effective in reducing NO_x emission levels.

DISCLAIMER

"This report was prepared by Combustion Engineering, Inc. as an account of work sponsored by the Office of Research and Development, U.S. Environmental Protection Agency (EPA). Combustion Engineering, Inc. nor any person acting on behalf of Combustion Engineering, Inc.:

"a. Makes any warranty or representation, expressed or implied including the warranties of fitness for a particular purpose or merchantability, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or

b. Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this report."

CONTENTS

	Page No.
Abstract	iii
Disclaimer	iv
List of Figures	vii
List of Data Sheets	ix
Acknowledgements	xi
Conclusions	1
Recommendations	3
Introduction	4
Purpose and Scope	4
Objectives	
Task I	7
Task II	7
Task III	7
Task IV	8
Task V	8
Task VI	8
Task VII	8
Task VIII	10
Task IX	10
Discussion	
Task I - Prepare the Design, Detail Fabrication and Erection Drawings	11
Task II - Purchase and Fabricate Equipment	11
Task III - Test Instrument Installation	13
Tasks IV & V - Baseline and Biased Firing Test Programs	15
Test Data Acquisition and Analysis	15
Load and Excess Air Variation	17
Furnace Wall Deposit Variation	21
Biased Firing - Fuel Elevations Out of Service Variation	26
Task VIII - Unit Optimization Study	34

CONTENTS (Cont'd)

	Page No.
Load and Excess Air Variation	34
Furnace Wall Deposit Variation	40
OFA Location & Rate Variation	44
OFA Tilt Variation	49
Load Variation at Optimum Conditions	51
Furnace Performance	55
Waterwall Corrosion Coupon Evaluation	57
Overfire Air Evaluation - Alternate Coals - Barry 4 Tests	70
Task IX - Prepare Application Guidelines	81
References	122
Appendix I	123
Compflow:Windbox - Compartment Air Flow Distribution Computer Program	

FIGURES

No.		Page No.
1	Unit Side Elevation	6
1A	Schematic - Overfire Air System	9
2	Program Schedule	12
3	Emission Test System	14
4	Corrosion Probe	18
5	Corrosion Probe Locations	19
6	Corrosion Probe Temperatures	20
7	NO_2 Vs. Theoretical Air to Fuel Firing Zone - Baseline Study	22
8	CO Vs. Theoretical Air to Fuel Firing Zone - Baseline Study	23
9	Percent Carbon Loss Vs. Theoretical Air to Fuel Firing Zone - Baseline Study	24
10	Unit Efficiency Vs. Unit Excess Air - Before Modification	25
11	Furnace Slag Pattern - Clean Furnace	27
12	Furnace Slag Pattern - Moderate Slag Furnace	28
13	Furnace Slag Pattern - Heavy Slag Furnace	29
14	NO_2 Vs. Theoretical Air to Fuel Firing Zone - Biased Firing Study	31
15	CO Vs. Theoretical Air to Fuel Firing Zone - Biased Firing Study	32
16	Percent Carbon Loss Vs. Theoretical Air to Fuel Firing Zone - Biased Firing Study	33
17	NO_2 Vs. Theoretical Air to Fuel Firing Zone - Overfire Air Study	36
18	CO Vs. Theoretical Air to Fuel Firing Zone - Overfire Air - Baseline Study	37
19	Percent Carbon Loss Vs. Theoretical Air to Fuel Firing Zone - Overfire Air & Baseline Study	38
20	Unit Efficiency Vs. Unit Excess Air - All Tests	39
21	Furnace Slag Pattern - Clean Furnace	41

FIGURES (Cont'd)

No.		Page No.
22	Furnace Slag Pattern - Moderate Slag Furnace	42
23	Furnace Slag Pattern - Heavy Slag Furnace	43
24	NO_2 Vs. Theoretical Air to Fuel Firing Zone - Overfire Air Study	45
25	CO Vs. Theoretical Air to Fuel Firing Zone - Overfire Air Study	47
26	Percent Carbon Loss Vs. Theoretical Air to Fuel Firing Zone - Overfire Air Study	48
27	NO_2 Vs. OFA Tilt & Fuel Nozzle Tilt	50
28	Percent Carbon Loss Vs. OFA Tilt & Fuel Nozzle Tilt	52
29	CO Vs. OFA Tilt & Fuel Nozzle Tilt	53
30	NO_2 Vs. Main Steam Flow: Normal & Optimum Operation	54
31	Chordal Thermocouple Locations	56
32	Waterwall Absorption - Baseline Operation	58
33	Waterwall Absorption - OFA Operation	59
34	Waterwall Absorption - OFA Operation	60
35	Waterwall Absorption - Baseline & OFA Operation	61
36	Gross MW Loading Vs. Time - Baseline Corrosion Probe Study	63
37	Gross MW Loading Vs. Time - Biased Firing Corrosion Probe Study	64
38	Gross MW Loading Vs. Time - Overfire Air Corrosion Probe Study	65
39	Ash Analysis - Corrosion Probe Studies	69
40	NO_2 Vs. Theoretical Air to the Firing Zone - Barry 4	74
41	NO_2 Vs. Excess Air - Barry 4	75
42	CO Vs. Excess Air - Barry 4	76
43	NO_2 Vs. Primary/Secondary Damper Positions - Barry 4	78
44	Waterwall Corrosion Probe Locations - Barry 4	80

DATA SHEETS

Sheet		Page No.
1	NO_x Test Data Summary - Baseline Study	82
2	NO_x Test Data Summary - Biased Firing Study	83
3	NO_x Test Data Summary - Baseline Study After Modification	84
4A	NO_x Test Data Summary - Overfire Air Location, Rate & Velocity Variation	85
4B	NO_x Test Data Summary - OFA Tilt Variation	86
4C	NO_x Test Data Summary - Load Variation at Optimum Conditions	86
5A, 5B	Test Data - Baseline Study	87, 88
6A, 6B	Test Data - Biased Firing Study	89, 90
7A, 7B	Test Data - Baseline Study After Modification	91, 92
8A, 8B	Test Data - Overfire Air Location, Rate & Velocity Variation	93, 94
8C, 8D	Test Data - Ovefire Air Tilt Variation and Load Variation at Optimum Conditions	95, 96
9A, 9B, 9C	Board Data - Baseline Study	97, 98, 99
10A, 10B, 10C	Board Data - Biased Firing Study	100, 101, 102
11A, 11B, 11C	Board Data - Baseline Study After Modification	103, 104, 105
12A, 12B	Board Data - Overfire Air Location, Rate & Velocity Variation	106, 107
12C, 12D, 12E	Board Data - Overfire Air Tilt Variation and Load Variation at Optimum Conditions	108, 109, 110

DATA SHEETS (Cont'd)

Sheet		Page No.
13A	Waterwall Absorption Rates - kg-cal/hr-cm^2 - Right Wall Centerline Tube Rates	111
13B	Waterwall Absorption Rates - kg-cal/hr-cm^2 - Front Wall Centerline Tube Rates	112
13C	Waterwall Absorption Rates - kg-cal/hr-cm^2 - Right Wall, Rear Wall, Left Wall, Front Wall	113
14A, 14B, 14C	Waterwall Corrosion Coupon Data Summary	114, 115, 116
15A, 15B	Test Data Summary, Barry No. 4	117, 118
16	Accelerated Corrosion Rate Data - Barry No. 4	119
17A, 17B	Typical Coal Analysis	120, 121

ACKNOWLEDGMENTS

The author wishes to acknowledge the constructive participation of Mr. D. G. Lachapelle, EPA Project Officer, in providing the program direction necessary for its successful completion.

The cooperation and active participation of Alabama Power Company and, in particular, the personnel of the Barry Steam Plant were essential to successfully modifying the test unit and conducting the various test program phases.

The results presented in this report represent the effort of many Combustion Engineering, Inc. personnel whose participation was required for its successful completion and in particular the technical contributions made by Messrs. W. A. Stevens, R. F. Swope, M. S. Hargrove, R. W. Robinson, R. W. Borio, R. M. Kantorak and E. R. LePage.

CONCLUSIONS

Normal Operation

1. Under normal unit operation without overfire air, excess air variation was found to have the greatest single effect on NO_x emission levels, increasing NO_x with increasing excess air. An average increase of 0.014 g $NO_2/10^6$cal for each 1% change in excess air was observed over the normal operating range.
2. Unit loading and variation in furnace slag conditions were found to have the least effect on NO_x and CO emission levels and the percent carbon in the flyash.
3. Under normal unit operation, the percent carbon loss in the fly ash and CO emission levels increased with decreasing excess air with the increases becoming greater below a level of approximately 20 to 25 percent excess air. CO levels in excess of 0.1 g/10^6cal were considered unacceptable for the purposes of this program.

Overfire Air Operation

1. NO_x reductions of 20 to 30% were obtained with 15 to 20 percent overfire air when operating at a total unit excess air of approximately 15 percent as measured at the economizer outlet. This condition would provide an <u>average</u> fuel firing zone stoichiometry of 95 to 100 percent of theoretical air. Stoichiometries below this level did not result in large enough decreases in NO_x levels to justify their use. Biased firing, while potentially as effective, necessitates a reduction in unit loading and is therefore less desirable as a method of NO_x control.
2. When using overfire air as a means of decreasing the theoretical air (TA)* to the fuel firing zone the percent carbon in the fly ash and CO emission levels were less affected than when operating with

---

* See Appendix I.

low excess air. This is due to the ability to maintain acceptable total excess air levels during overfire air operation.

3. Furnace performance as indicated by waterwall slag accumulations, visual observations and absorption rates were not significantly affected by overfire air operation.
4. On the test unit, where the overfire air port could not be installed as a windbox extension, test results indicated that the centerline of the overfire air port should be kept within 3 meters of the centerline of the top fuel elevation. Distances greater than 3 meters did not result in decreased NO_x levels. Changes in distance less than 3 meters did affect NO_x levels to a limited extent with the NO_x level increasing with decreasing distance.
5. Optimum overfire air operation was obtained with the test unit when the overfire air nozzles were tilted with the fuel nozzles. From a standpoint of NO_x control, emission levels increased when the nozzles were directed toward each other, and flame stability decreased when they were directed away from each other by more than 20-25°. With the overfire air tilts fixed in a horizontal position, acceptable unit operation was obtained, however, NO_x levels varied with fuel nozzle position.
6. The results of the 30 day baseline, biased firing and overfire air corrosion coupon runs indicate that the overfire air operation for low NO_x optimization did not result in significant increases in corrosion coupon degradation. Additional studies will be required to verify these observations over long-term operation.
7. Variables normally used to control normal boiler operation should not be considered as NO_x controls with coal firing. These variables include unit load, nozzle tilt, pulverizer fineness, windbox dampers and total excess air.
8. Overall unit efficiency was not significantly affected by overfire air operation.

RECOMMENDATIONS

This program investigated the effects of employing biased firing and overfire air, as incorporated on a specially modified unit, as methods for controlling NO_x emission levels in existing steam generating units.

These control methods were studied using an Eastern United States bituminous coal type. Due to the location of the test site it was not, however, within the scope of this program to investigate coal types located in the western areas of the United States.

1. As these western coal types are becoming a more predominate source of fuel for electric generating stations, it was recommended in the Task V interim report that studies be undertaken to include their evaluation. EPA Contract 68-02-1486 was subsequently awarded to Combustion Engineering, Inc. to study western coal fuels. In this program new units being designed with overfire air systems as an extension to the windbox will be utilized eliminating the need for unit modifications while expanding the experimental studies to include test data for larger current design steam generating units.
2. Additionally, the results of the corrosion probe evaluations indicate that the coupon weight losses encountered during a 30 day evaluation are small and consideration should be given to studies of up to one year duration to verify short term test results. These studies should include evaluation of actual fireside waterwall tube wastage rates as well as corrosion probe wastage rates.

INTRODUCTION

Purpose and Scope

This program encompassed the work to be performed under the second phase of a two phase program to identify, develop and recommend the most promising combustion modification techniques for the reduction of NO_x emissions from tangentially coal-fired utility boilers with a minimum impact on unit performance.

Phase I (performed under EPA Contract 68-02-0264) consisted of selecting a suitable utility field boiler to be modified for experimental studies to evaluate NO_x emission control. Phase I also included the preparation of preliminary drawings, a detailed preliminary test program, a cost estimate and detailed schedule of the program phases and a preliminary application economic study indicating the cost range of a variety of combustion modification techniques applicable to existing and new boilers. (1)

Phase II consisted of modifying and testing the utility boiler selected in Phase I to evaluate overfire air and biased firing as methods for NO_x control. This phase also included the completion of detailed fabrication and erection drawings, installation of analytical test equipment, updating of the preliminary test program, analysis and reporting of test results and the development of control technology application guidelines for existing and new tangentially coal-fired utility boilers.

This program was conducted at the Barry Steam Station, Unit No. 2 of the Alabama Power Company. This unit is a natural circulation, balanced draft design, firing coal through four elevations of tilting tangential fuel nozzles. Unit capacity at maximum continuous rating (MCR) is 408,000 kg/hr main steam flow with a superheat outlet temperature and pressure of 538°C and 131.8 kg/cm^2. Superheat and reheat temperatures are controlled by fuel nozzle tilt and spray desuperheating. A side

elevation of the unit prior to modification is shown on Figure 1.

Throughout this report NO_x emission levels are expressed as $g/10^6$cal NO_2.

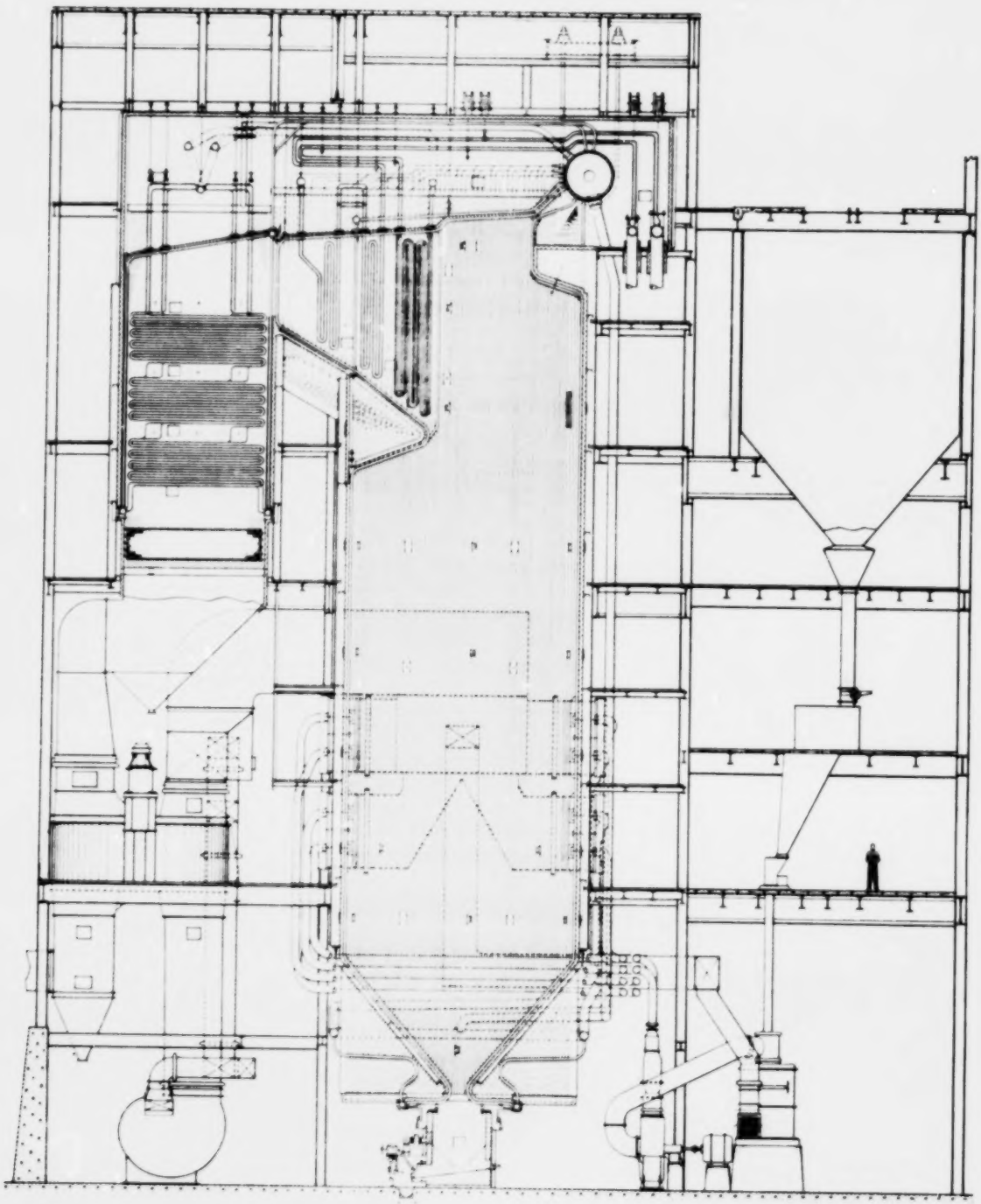


Figure 1. Unit Side Elevation, Alabama Power Company, Barry No. 2

OBJECTIVES

The objective of program Phase II was to complete the design of the overfire air system, modify the Barry 2 unit accordingly, perform baseline, biased firing and optimization tests and based on the results of this program, prepare an application guideline for the NO_x control technology generated.

Specifically these objectives are defined as follows:

Task I - Prepare the design, detailed fabrication and erection drawings necessary for modification of Barry No. 2 to incorporate an overfire air system. The system design provides for:

a. Introducing a maximum of 20% of the total combustion air above the fuel admission nozzles.

b. Overfire air introduction through the top two existing windbox compartments (thereby prohibiting the use of one elevation of fuel nozzles).

c. Introduction of hot overfire air only with consideration for air preheat control.

An updated schedule for Tasks II and IV were also prepared under Task I.

Task II - Complete the purchasing and fabrication of all equipment necessary for modification of the Barry No. 2 unit.

Task III - Install all necessary instrumentation required to measure flue gas constituents and characterize the effects of combustion modifications on unit performance. Specifically the following determinations were made:

a. Flue gas constituents: NO_x, SO_x, CO, HC, O_2

b. Unit Performance Effects:

Fireside corrosion
Furnace heat absorption
Sensible heat leaving furnace
Superheater, reheater and air heater performance

Task IV - Conduct a baseline test program to establish the effect of unit load, wall slagging and excess air variation on baseline emission levels, thermal performance and operating ranges. A baseline corrosion coupon test of 30 day duration was also conducted.

Task V - Conduct a biased firing baseline test program to establish the effect on unit emission levels while operating with various fuel elevations out of service. These tests were performed specifically to evaluate the maximum emission control at full load and throughout the normal load range. In addition, the degree of control required to meet and maintain emission standards throughout the normal control range was also evaluated. A biased firing corrosion coupon test of 30 days duration was also conducted.

Task VI - Install all equipment required for modification of the test unit and functionally check equipment to determine that proper operation is obtained. (See Figure 1A)

Task VII - Complete final preparations for conducting the overfire air test program to be conducted in Task VIII including the following:

a. Finish installation of the furnace waterwall thermocouples.
b. Check out all necessary test instrumentation for proper installation and operation.
c. Review test program with EPA project officer and util-

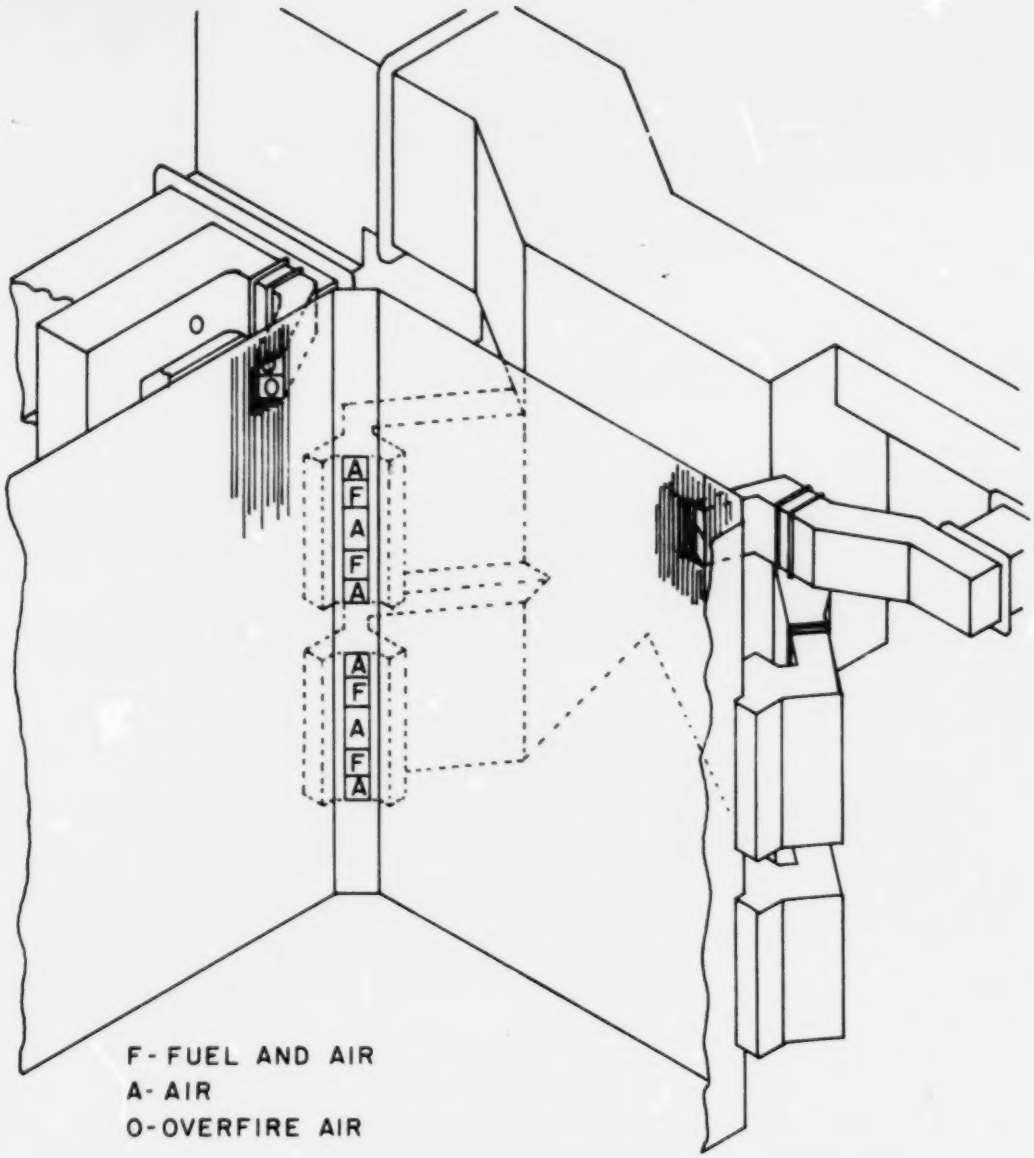


Figure 1A: Schematic Overfire Air System, Barry No. 2

ity company.*

d. Perform a final inspection of the test unit to assure proper operation.

Task VIII- Conduct the overfire air test program, analyze the data generated and compare this data with that obtained during Task V. The program investigated the effect of overfire air location and rate at various unit loadings and evaluated operating conditions considered as optimum from the standpoint of NO_x control and unit operation. The final report was also generated under tnis Task.

Task IX - Prepare a program outlining the application of the technology developed under this study to existing and new design tangentially coal-fired utility boilers. These application guidelines will be submitted as a separate final report.

---

* The test program for this study was originated during the Phase I study, Contract 68-02-0264 and was included as part of the Phase I report.

DISCUSSION

Task I - Prepare the Design, Detailed Fabrication and Erection Drawings

Engineering Drawings

The drawings necessary for the design and installation of the overfire air system were completed by the end of the eighth program month and were submitted to the EPA for review and approval as they were completed. The design provides for the introduction of 20% of the total combustion air as overfire air above the existing fuel admission zone. These compartments are located approximately 2.4 meters above the existing windbox. In addition overfire air can be introduced through the top two compartments of the existing windbox. The current design provides for the introduction of hot overfire air only.

Updated Time Schedule

The Phase II program schedule was reviewed and updated relative to the coordination of Tasks II, IV and V with the test unit outage.

The scheduling of the unit outage was coordinated with Alabama Power Company and reviewed periodically to assure that the unit modification would occur as scheduled. The final program schedule presenting the actual periods of performance for Phase II is shown on Figure 2.

Task II - Purchase and Fabricate Equipment

The equipment for modification of the Barry No. 2 unit to incorporate overfire air as an NO_x control was assembled and ready to be shipped to the test site by the end of the eighth program month. Completion of equipment fabrication by this date permitted necessary time for delivery of the equipment to the job site and performing any possible pre-outage erection which would be accomplished prior to the unit outage.

In addition, instrumentation required for the baseline and optimization test phases of the program was calibrated, fabricated and prepared for shipment to the job site. This effort included fabrication of corrosion

Figure 2: Program Schedule for Evaluation of Biased and Overfire Air Firing and Existing Process Variables

probes, probe control systems, and gas sampling probes, and calibration of thermocouples, analyzers and transducers. The emissions monitoring system is shown in Figure 3.

Task III - Test Instrumentation Installation

The analytical test instrumentation necessary for the measurement of flue gas constituents and unit performance were installed by the fifth program month with the exception of the waterwall absorption thermocouples which were installed during the unit outage for installation of the overfire air modification.

The instrumentation and analytical methods used were as follows:

Measurement	Instrument/Analytical Procedure
Flue Gas Constituents	
NO_x	Chemiluminescence Analyzer
SO_2	Wet Chemistry
CO & Hydrocarbons	Infrared Analy. and Flame Ionization Analyzer
Carbon Loss	Dust Collector
Oxygen	Paramagnetic Analyzer
Fuel Analysis	ASTM Procedures
Ash Analysis	ASTM Procedures
Flow Rates	
Steam & Water	
Feedwater Flow	Flow Orifice
Reheat and Superheat Desuperheat Spray	Heat Balance (°F & PSIG) Around Desuperheater
Reheat Flow	Heat Balance Around Superheat Extractions and Estimated Turbine Gland Seal Losses

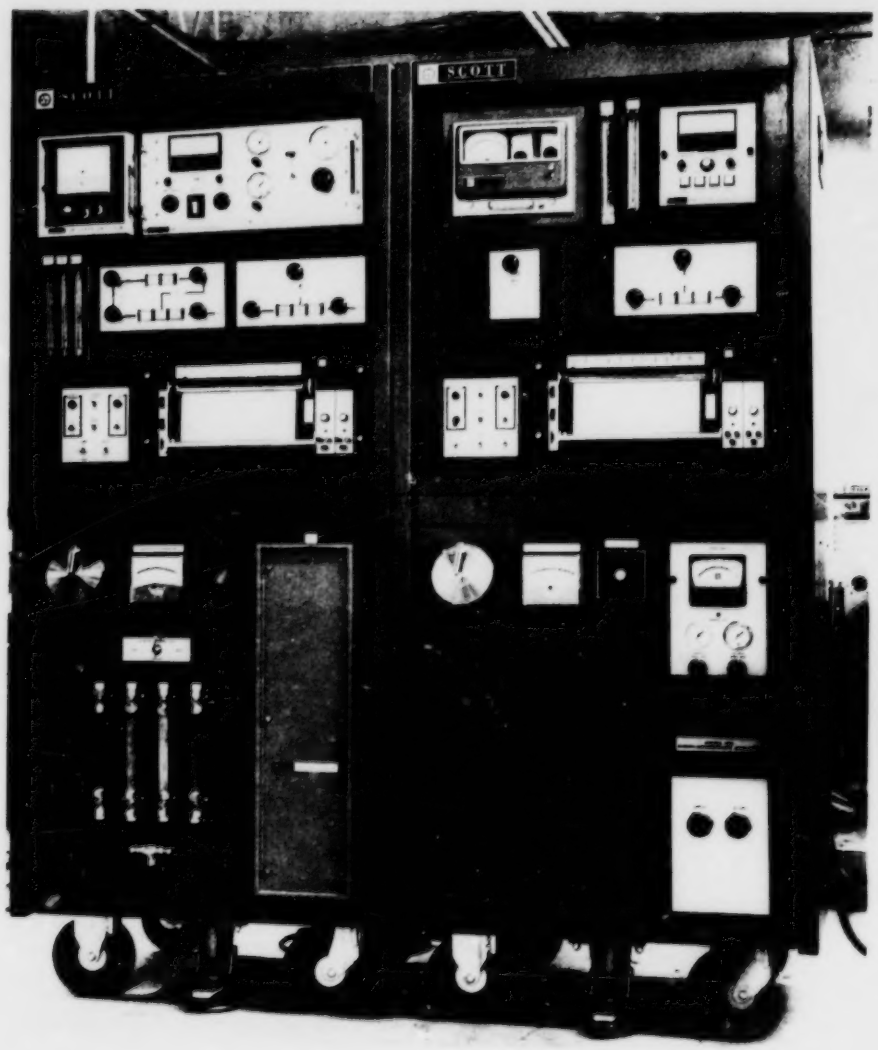


Figure 3. Gaseous Emissions Test System

Measurement	Instrument/Analytical Procedure
Air & Gas	
Total Air & Gas Weight	Calculated
Overfire Air*	Pitot Traverse
Air Heater Leakage	Paramagnetic O_2 Analyzer
Temperatures	
Steam & Water °F	
Unit Absorption Rates	Calibrated Stainless Steel Sheathed CR-C Well & Button TC's
Waterwall Absorption*	Calibrated Stainless Steel Sheathed Cr-C Chordal WW TC's
Air & Gas °F	Cr-C TC's Water Cooled Probes Pt/Pt-10% Rh TC's
Pressures	
Steam and Water PSIG	
Unit Absorption Rates	Pressure Gauges and/or Transducers
Unit Draft Loss	Water Manometers
Temperature and Pressure Logging, °F & PSI	C-E Data Logger Capacity: 400 temperatures, 50 pressures

Tasks IV & V Baseline & Biased Firing Test Programs

Test Data Acquisition and Analysis

The flue gas samples for determination of NO_x, O_2, CO, SO_2 and HC emission levels were obtained at each of the two economizer outlet ducts.

---

* Installed during Task VI

The flue gas samples were drawn from a twenty-four (24) point grid arranged on centroids of equal area in each duct with the exception of the SO_2 sample which was drawn from a single average point using a heated sample line. Fly ash samples for carbon loss analysis and dust loading were obtained at a single point in each duct.

The percent O_2 leaving the air preheaters was also determined using a twenty-four (24) point grid arranged in centroids of equal area for the determination of air preheater leakage and unit efficiency.

The following instrumentation was used in determining the emission concentrations:

1. NO_x: Chemiluminescence Analyzer
2. O_2: Paramagnetic Analyzer
3. CO: Nondispersive Infrared Analyzer
4. HC: Flame Ionization Analyzer
5. SO_2: Wet Chemistry
6. Carbon Loss & Dust Loading: ASME Particulate Sampling Train

A summary of the NO_x emission test data is tabulated on Data Sheets 1, 2, 3 and 4.

Unit steam and gas side performance was monitored using calibrated thermocouples, pressure gauges, transducers and manometers as required.

Coal samples were obtained during each test for later analysis. The samples were obtained from each feeder and blended to form a composite sample. Fuel analyses, unit steam flow rates, absorption rates, gas and air weights and efficiencies were calculated for each test run. Unit efficiency was determined using the heat losses method (based on ASME power test code 4.1-1964). The measured and calculated unit performance test data is presented on Data Sheets 5, 6, 7 and 8. A complete set of

unit board data was obtained for each test run and is presented on Data Sheets 9, 10, 11 and 12. While Data Sheets 1 through 8 are reported in metric units, the board data (Sheets 9 through 12) are reported in the engineering units as taken. The 30 day waterwall corrosion coupon evaluation was conducted using a specially designed probe consisting of four individual coupons shown in Figure 4. Individual probes were exposed at five locations on the front furnace wall as shown on Figure 5. A typical trace of the control temperature range for each of the twenty coupons is shown on Figure 6. The control temperature ranges were the same for the baseline, biased firing and overfire air studies.

Task IV Baseline Test Study

Load and Excess Air Variation

Tests 1 through 7 were conducted to determine the effect of varying excess air at three unit loads on unit emission levels and performance. These tests were conducted with clean furnace conditions.

As shown in the following table, NO_x emission levels increased with increased excess air but did not change significantly with changes in unit loading. An average increase of 0.014 g $NO_2/10^6$ cal was noted for each 1% change in excess air over the normal unit operating range.

Load & Excess Air Variation

Test No.	Main Steam Flow 10^3 kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air to Firing Zone %	Unit Eff. %	WW Slag
1	219	1.337	0.032	35.5	130.6	88.3	Clean
2	224	1.030	0.182	17.5	117.1	88.2	Clean
3	214	1.519	0.010	58.9	151.3	87.6	Clean
4	316	0.90	0.050	12.6	109.2	89.3	Clean
5	404	1.041	0.040	22.7	117.9	89.0	Clean
6	407	0.761	0.198	11.7	107.2	89.1	Clean
7	405	1.403	0.042	30.8	125.3	89.5	Clean

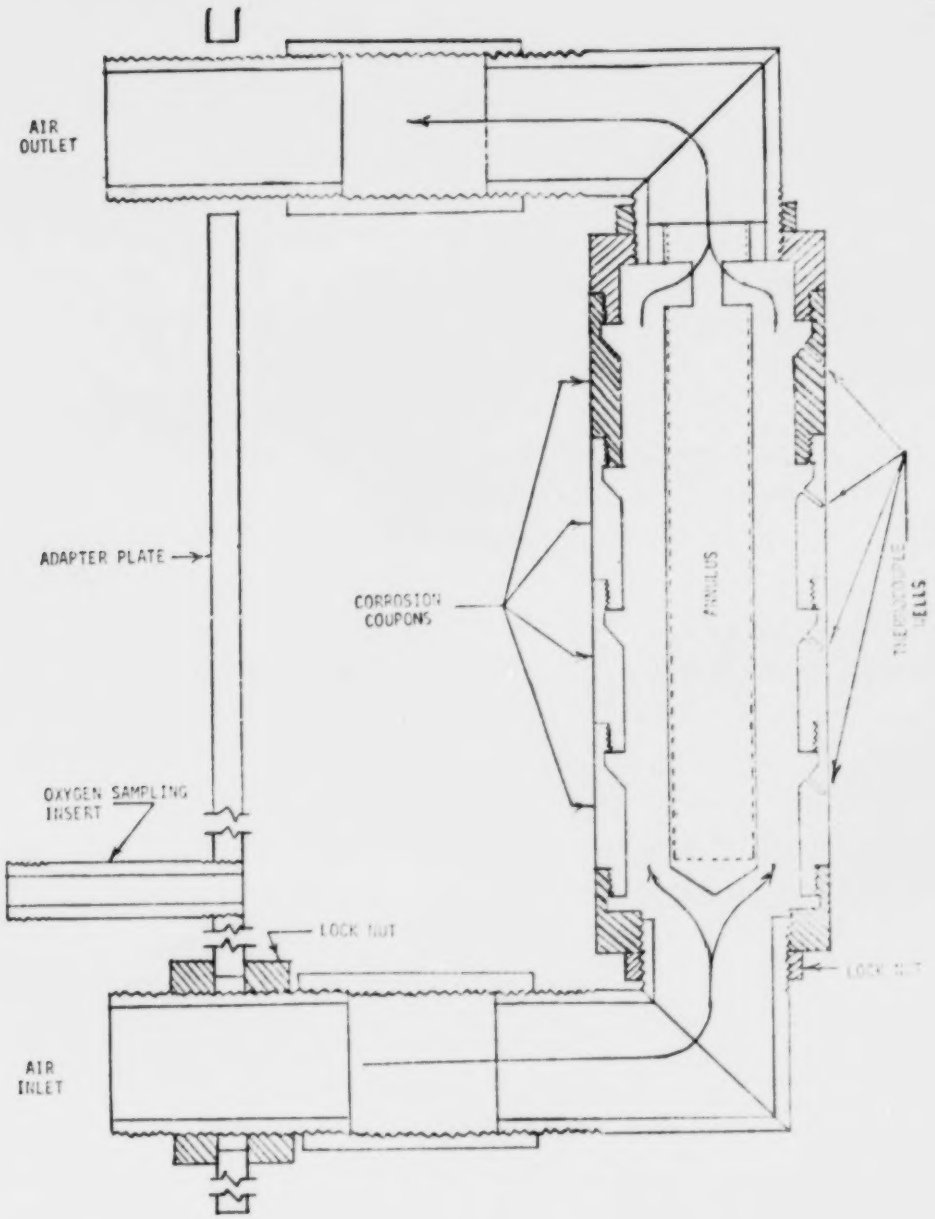


Figure 4: Corrosion Probe Assembly Drawing

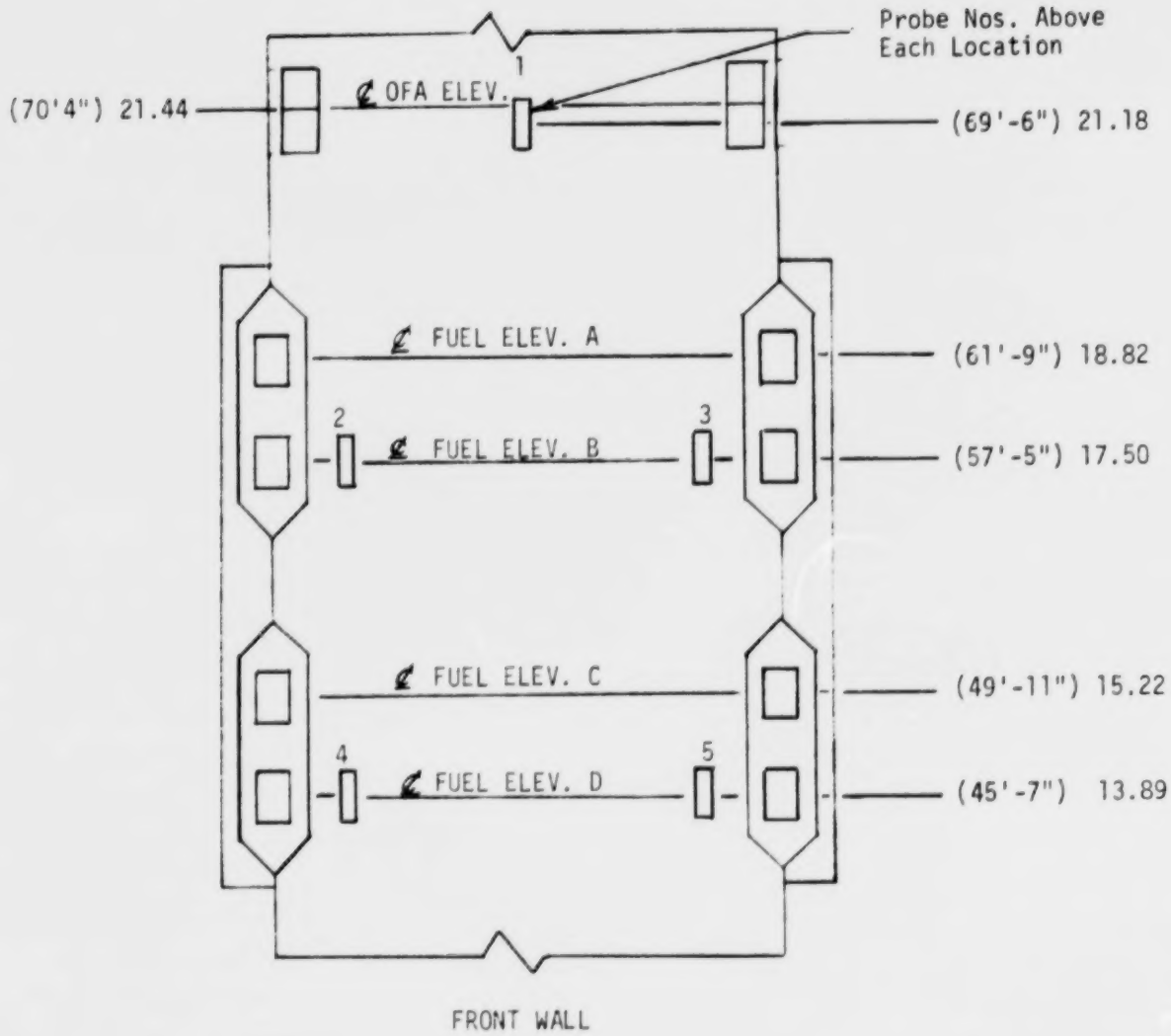


Figure 5. Waterwall Corrosion Probe Locations, Alabama Power Company Barry No. 2

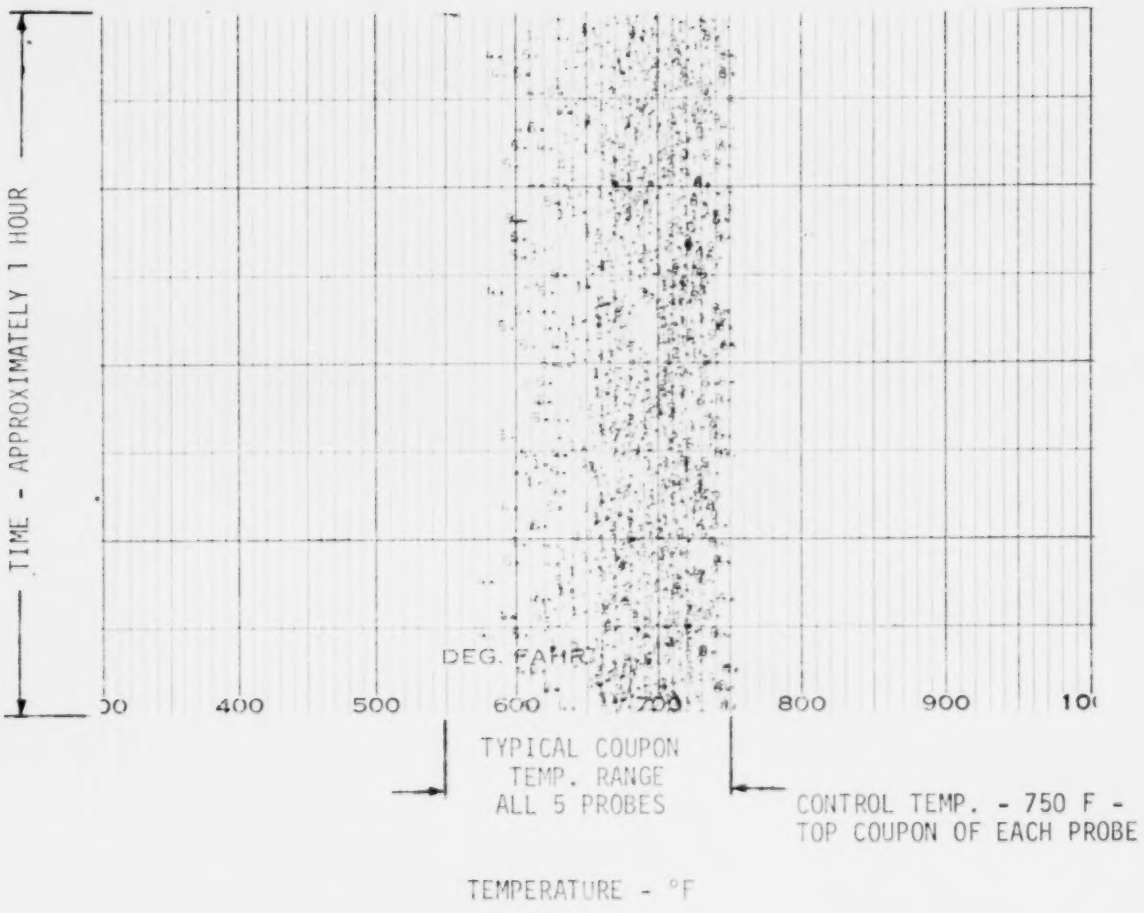


Figure 6: Typical Corrosion Probe Temperature Range

A maximum excess air limit of 30.8 and 58.9 percent was obtained at full and half load conditions respectively due to ID fan capacities.

Minimum excess air limits of 20 to 25 percent were determined as those at which acceptable CO emission levels could be maintained. Reduction of NO_2 emission levels using excess air reduction was therefore limited to approximately 1.04 g/10^6cal as obtained during Test 5.

The changes in NO_2, CO, percent carbon loss in the fly ash and unit efficiency versus theoretical air to the fuel firing zone are shown on Figures 7, 8, 9 and 10, respectively. The theoretical air (TA) to the firing zone is used in this case as it accounts for variations in position and leakage in the compartment dampers above the top active fuel compartment and thereby presents a more accurate determination of the actual air available for combustion in the fuel firing zone than does the total excess air. As seen on Figure 7 for clean furnace conditions the NO_2 correlates well with TA with little variation due to unit load. As shown on Figures 8 and 9 carbon loss in the fly ash and CO emission levels increased with decreased TA levels. Unit load does not appear to have a discernable effect. Figure 10 is a plot of Unit Efficiency versus Unit Excess Air measured at the economizer outlet.

During this portion of the test program total hydrocarbon levels (HC) were monitored and were found to be present in only trace quantities as shown on Data Sheets 1 and 2. The SO_2 levels measured are also shown on Data Sheets 1 and 2.

Furnace Wall Deposit Variation

Tests 8 through 14 were conducted to determine the effect on unit performance and emission levels of varying furnace waterwall deposits from a clean condition to the maximum possible slagging condition obtainable. The maximum slagging condition was obtained after operation in excess of twenty-four hours without operating any wall blowers. During this

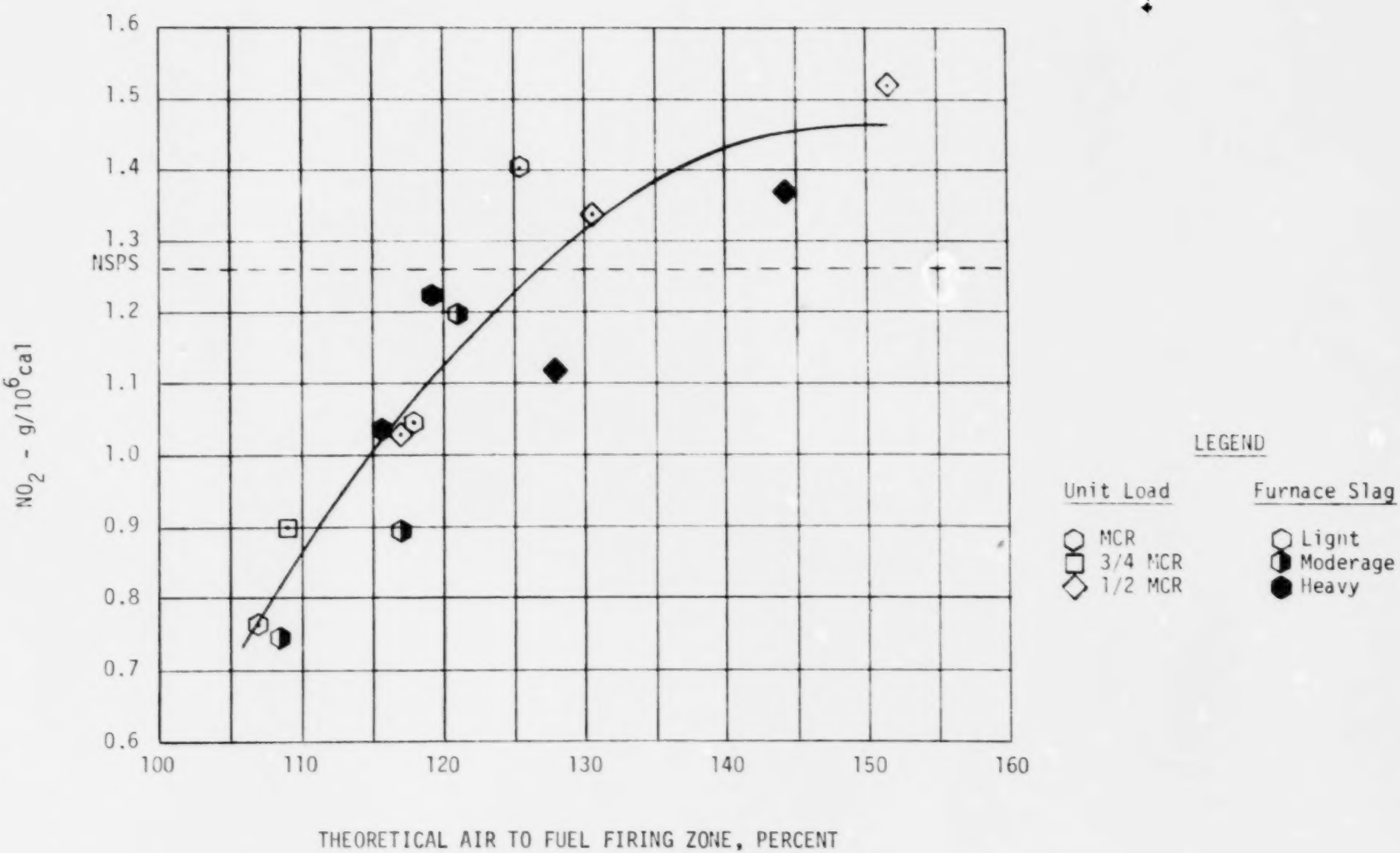


Figure 7: NO_2 Vs. Theoretical Air to Fuel Firing Zone, Baseline Study, Tests 1-14

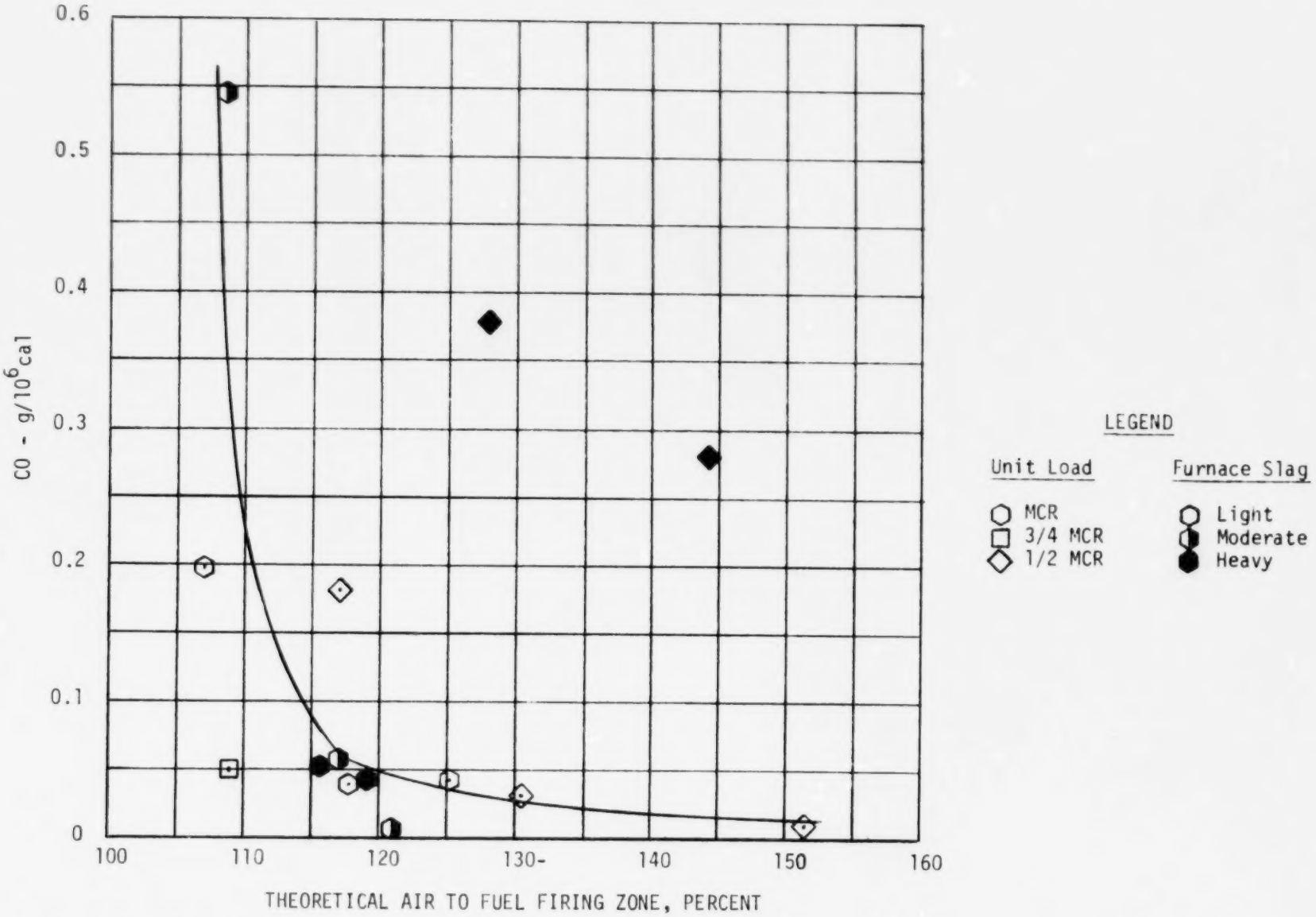


Figure 8: CO Vs. Theoretical Air to Fuel Firing Zone, Baseline Study, Tests 1-14

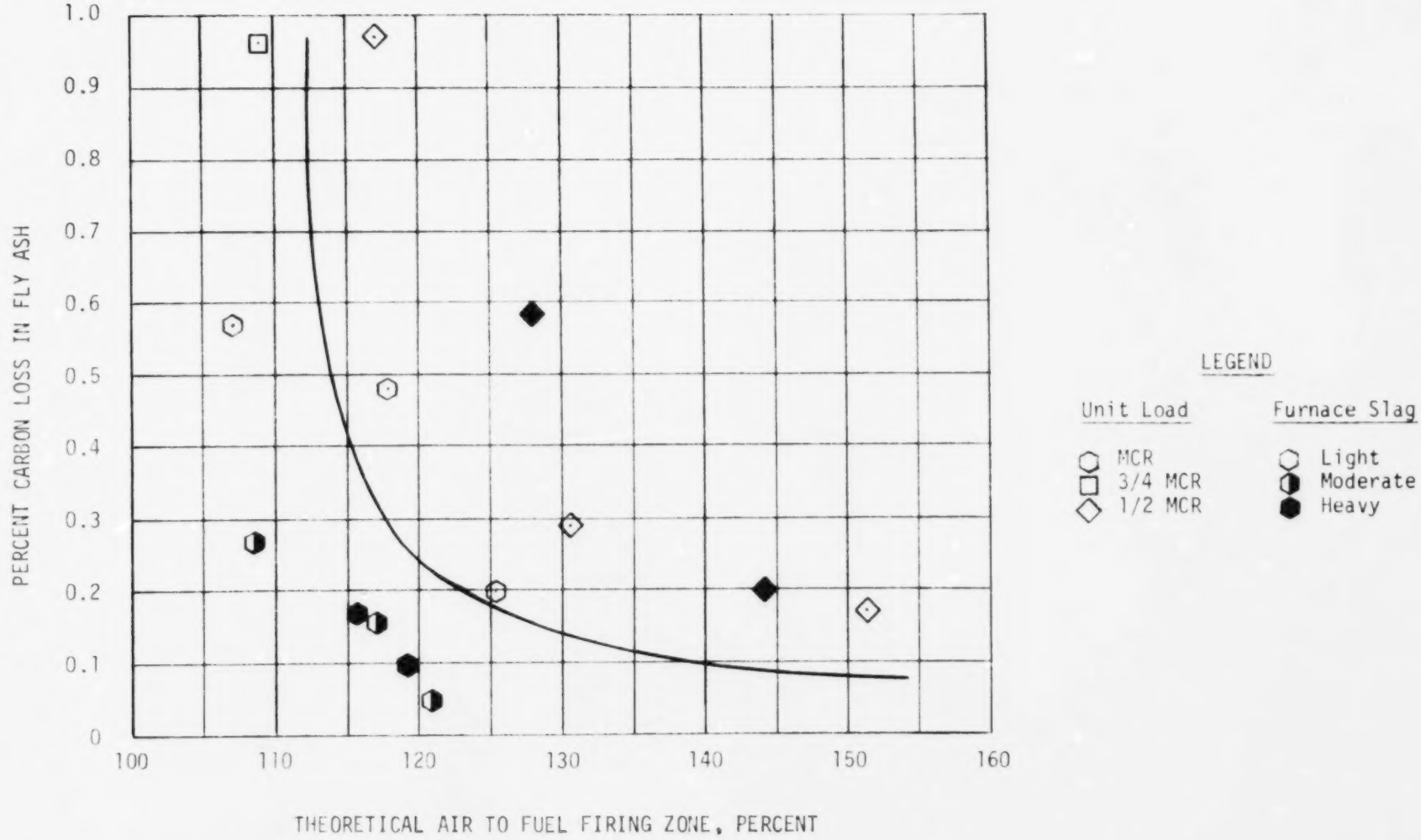


Figure 9: Percent Carbon Loss Vs. Theoretical Air to Fuel Firing Zone, Baseline Study, Tests 1-14

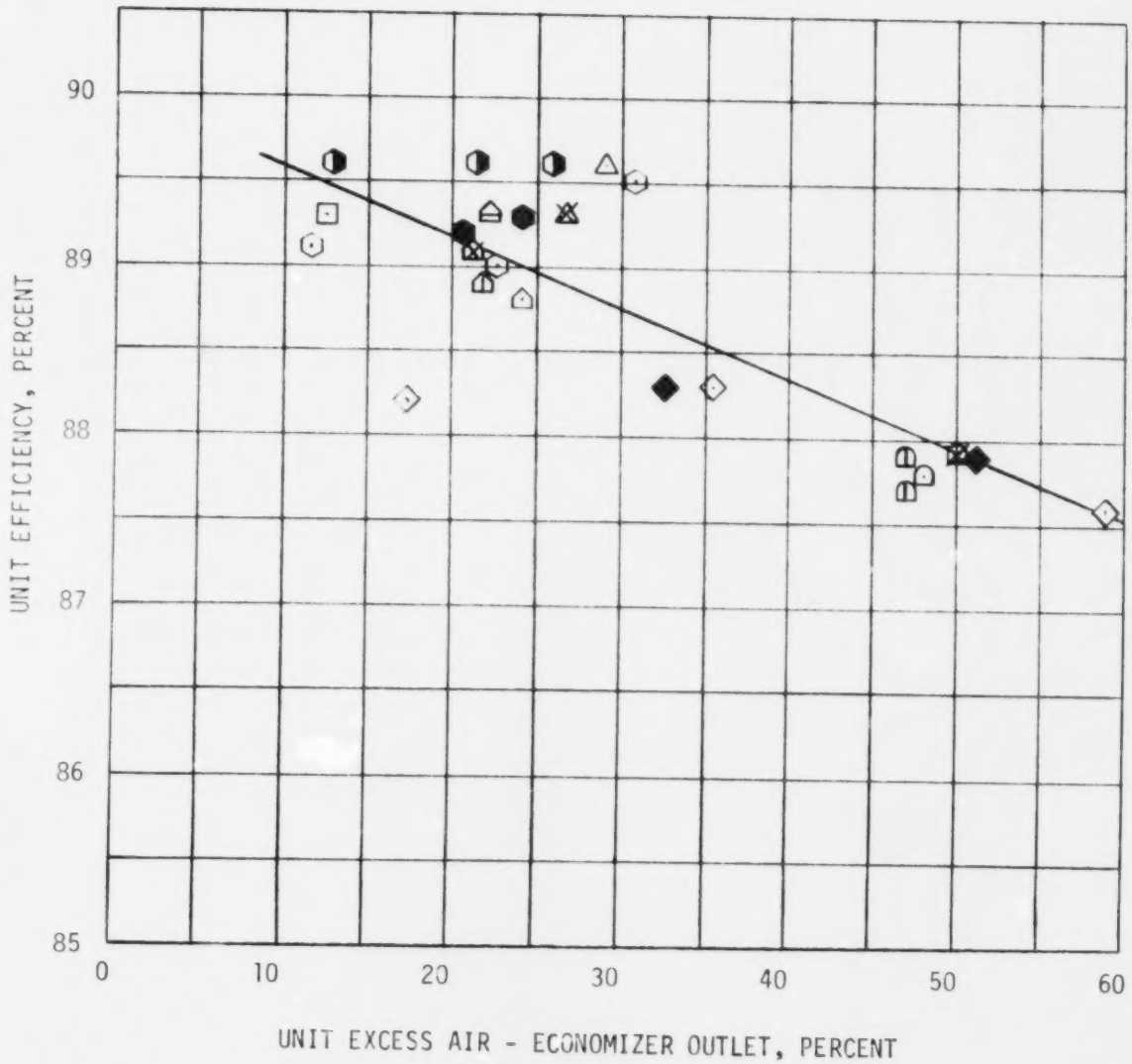


Figure 10: Unit Efficiency Vs. Unit Excess Air

time period slag deposits of up to 4 inches in thickness could be obtained in and above the fuel firing zone.

Furnace Wall Deposit Variation

Test No.	Main Steam Flow 10^3 kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air to Firing Zone %	Unit Eff. %	WW Slag
8	411	0.894	0.059	21.5	116.9	89.6	1/2 Max Dep
9	403	0.748	0.545	13.0	108.5	89.6	1/2 Max Dep
10	405	1.198	0.007	26.0	120.8	89.6	1/2 Max Dep
11	211	1.118	0.378	32.7	128.0	88.3	Max Dep
12	206	1.370	0.280	51.2	144.1	87.9	Max Dep
13	412	1.037	0.052	20.7	115.7	89.2	Max Dep
14	406	1.225	0.043	24.3	119.2	89.3	Max Dep

As can be seen from Figure 7 furnace slagging did not exhibit a discernable effect on NO_x emission levels. As shown in Figures 8 and 9 this condition was also found to be true for carbon loss in the fly ash and CO emission levels with the exception of the half load Tests 11 and 12 where CO levels higher than those obtained with clean furnace conditions were observed. The high CO levels may have been due to slag build-up at or near the fuel and air nozzles which could have contributed to poor combustion. The higher CO levels were not observed under full load with heavy slag operation. Figure 10 indicates that furnace cleanliness did not exhibit any discernable effect on unit efficiency.

Slag patterns taken during clean, moderate and heavy slagging conditions at full load operation are shown on Figures 11, 12 and 13.

Task V - Biased Firing Study - Fuel Elevations Out of Service Variation

Tests 15 through 24 were conducted to determine the effect on NO_x emission levels of taking various fuel elevations out of service (biased firing) at various unit loadings. As shown on the following table the

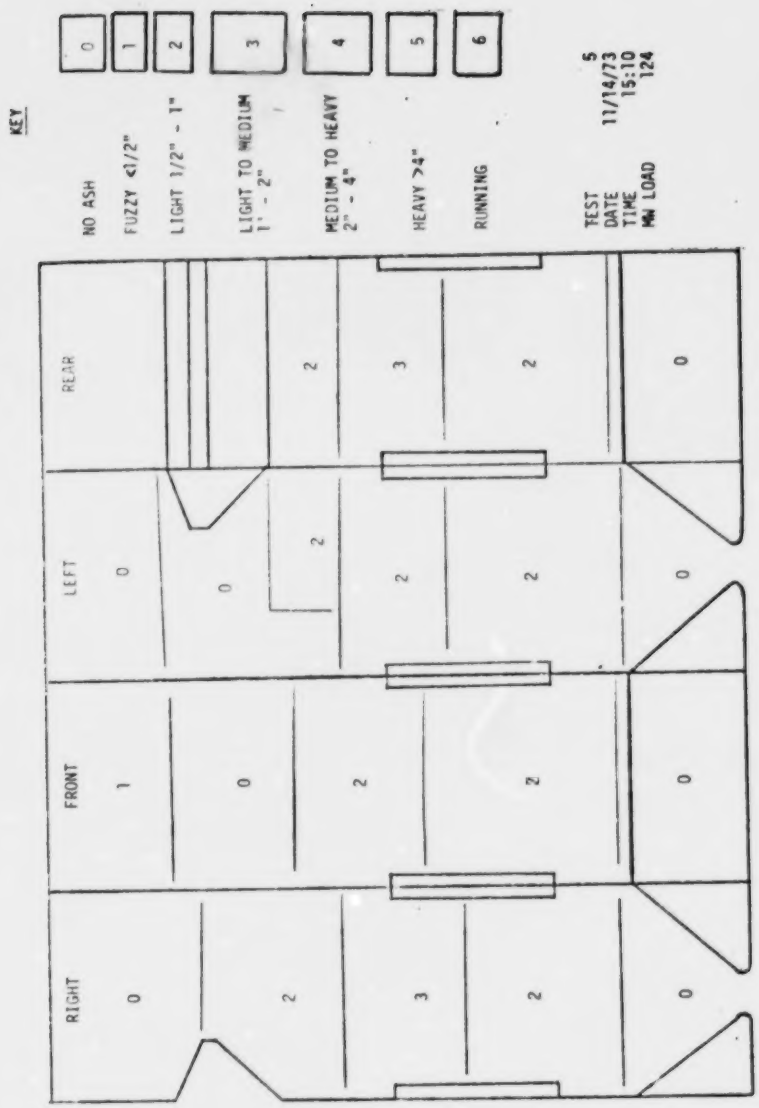


Figure 11: Furnace Slag Pattern, Clean Furnace

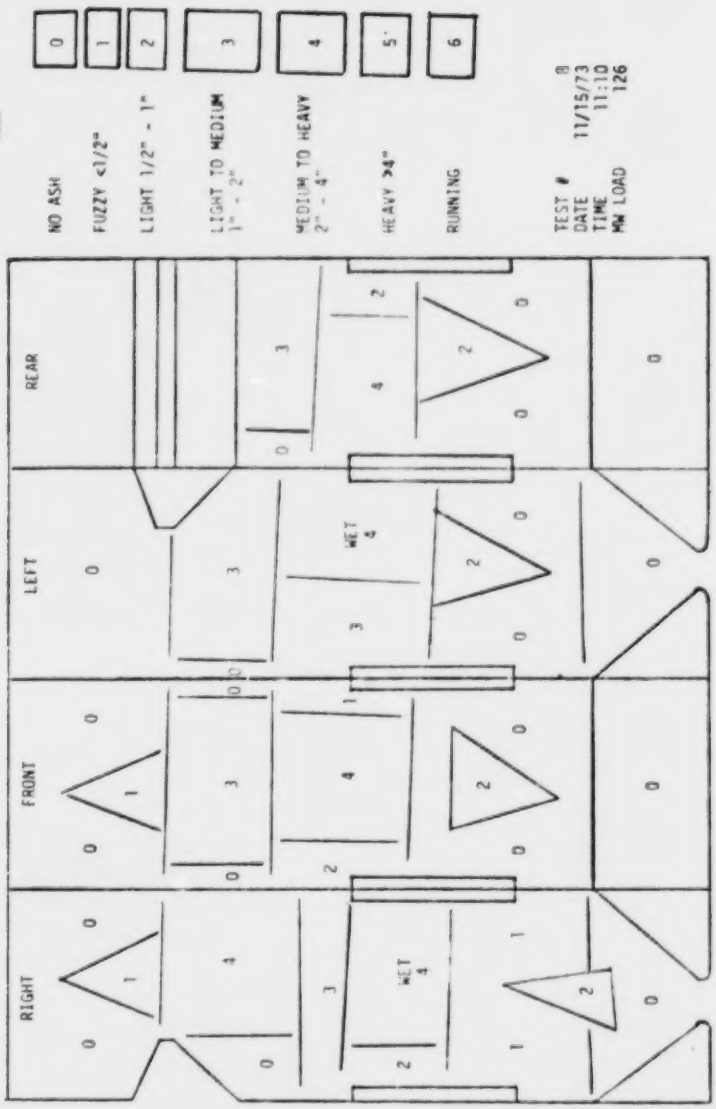


Figure 12: Furnace Slag Pattern, Moderate Slag Furnace

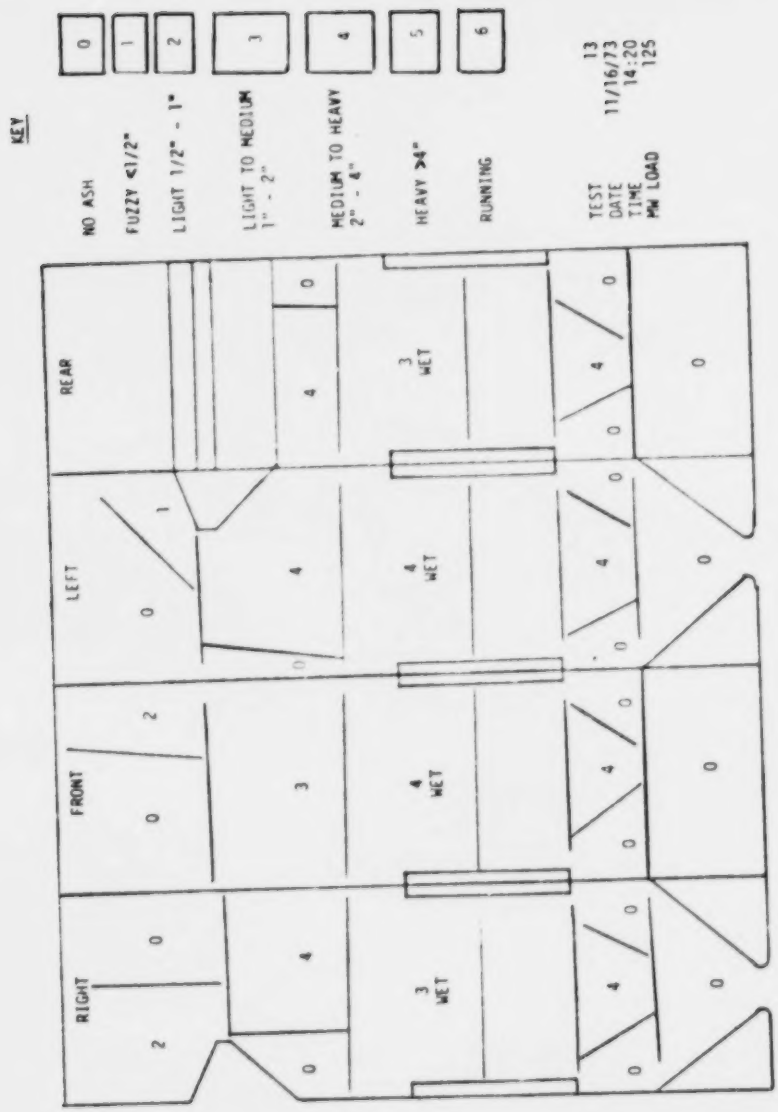


Figure 13: Furnace Slag Pattern, Heavy Slag Furnace

maximum NO_x emissions control was obtained with the top elevation of fuel nozzles out of service at maximum and 75 percent maximum loading (Tests 20 and 21). At 50 percent maximum loading (Test 23) the high excess air levels required to maintain unit steam temperatures appeared to negate any NO_x reductions obtained by biasing the top fuel nozzle elevation, however, the emissions level obtained was below the current EPA limit for coal fired units of 1.26 $g/10^6$cal.

Biased Firing - Fuel Elevations Variation

Test No.	Main Steam Flow 10^3kg/hr	NO_2 $g/10^6$cal	CO $g/10^6$cal	EA %	Theo. Air to Firing Zone %	Unit Eff %	Fuel Nozzle Elevation Out Of Service
15	199	1.206	0.041	50.1	105.8	87.9	Bottom
16	297	1.142	0.037	26.7	121.7	89.3	Bottom
17	315	0.840	0.059	21.1	116.5	89.1	Bottom
18	321	0.792	0.050	22.2	117.5	89.3	Bot. Ctr.
19	321	0.795	0.044	21.8	117.2	88.9	Top Ctr.
20	314	0.599	0.034	24.2	94.7	88.8	Top
21	308	0.696	0.040	29.0	97.3	89.6	Top
22	208	1.124	0.038	48.0	112.5	87.8	Top
23	211	1.043	0.029	47.0	141.4	87.9	Top Ctr.
24	202	1.282	0.035	47.0	141.3	87.7	Bot. Ctr.

As can be seen from Figure 14 biasing the center two and bottom fuel elevations did not have a discernable effect on NO_x emission levels although the emission level tended to be higher at reduced unit loadings for given TA levels.

Figures 15 and 16 indicate that with biased firing, low TA levels to the fuel firing zone were obtained without increasing either CO emission levels or the carbon loss in the fly ash. Figure 10 shows that biased firing operation did not significantly affect unit efficiency. This condition is due to the ability to maintain acceptable total unit excess air levels during biased firing operation.

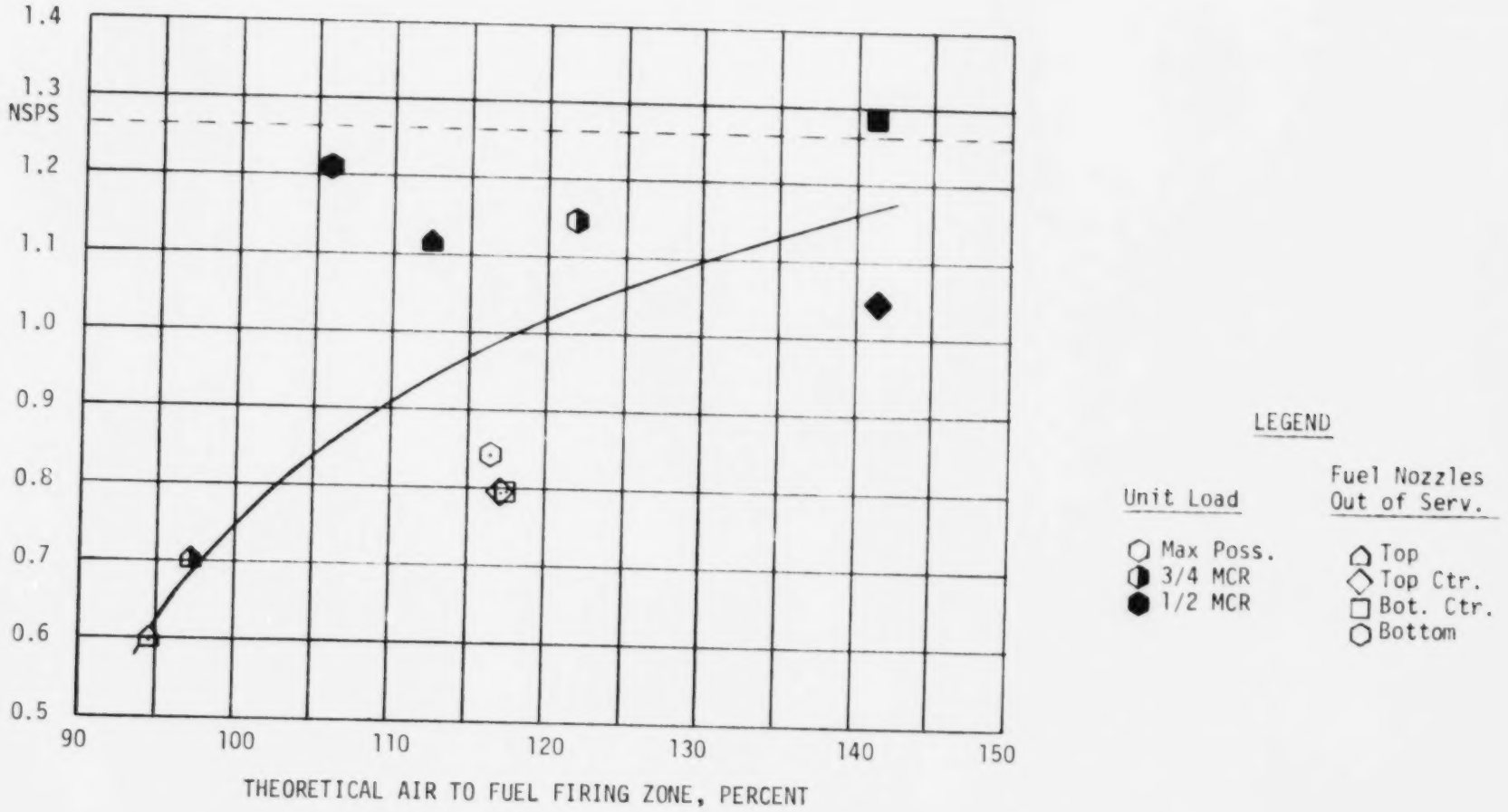


Figure 14: NO_2 Vs. Theoretical Air to Fuel Firing Zone, Biased Firing Study, Tests 15-24

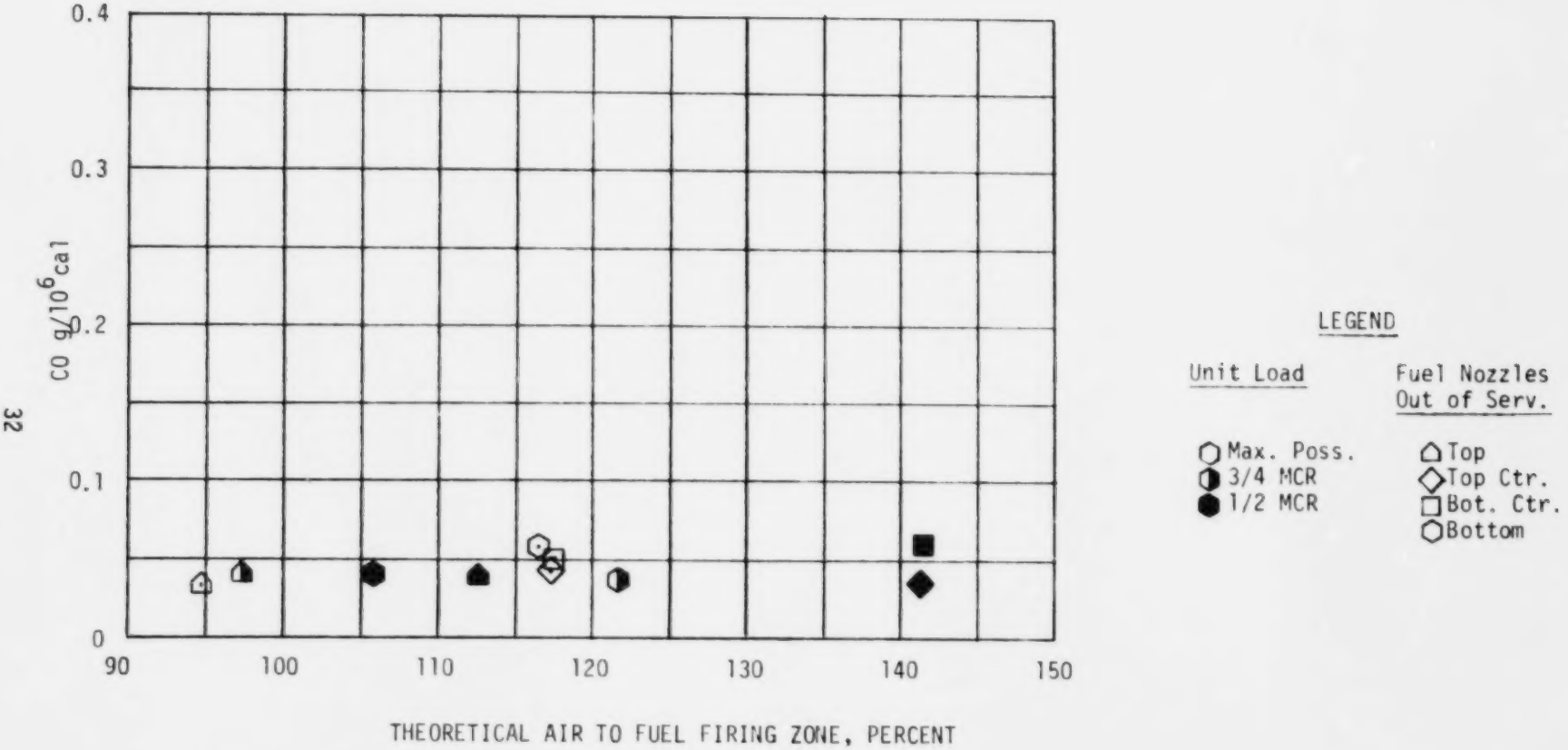


Figure 15: CO vs. Theoretical Air to Fuel Firing Zone, Biased Firing Study, Tests 15-24

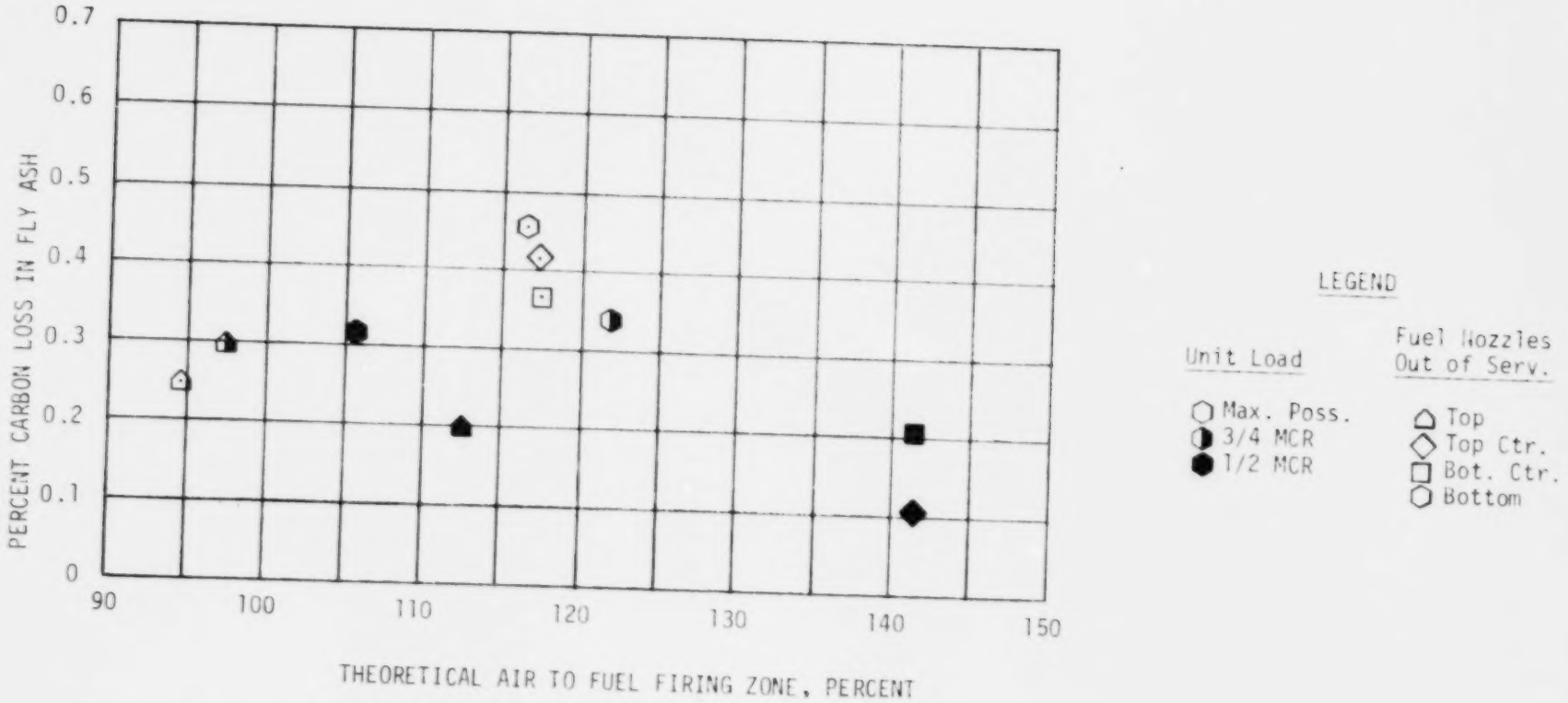


Figure 16: Percent Carbon Loss Vs. Theoretical Air to Fuel Firing Zone, Biased Firing Study Tests 15-24

Task VIII - Unit Optimization Study

Load and Excess Air Variation (After Modification)

Load & Excess Air Variation

Test No.	Main Steam Flow 10^3kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air Firing Zone %	Unit Eff. %	WW Slag
1	219	0.929	0.035	33.5	127.1	88.4	Clean
2	213	0.701	0.479	16.0	113.4	88.8	Clean
3	217	1.339	0.044	64.7	155.4	87.4	Clean
4	315	0.684	0.140	15.5	111.0	89.8	Clean
5	450	0.846	0.037	21.0	115.3	89.4	Clean
6	441	0.692	0.162	12.4	107.1	89.2	Clean
7	423	1.000	0.028	25.4	119.5	89.5	Clean

Tests 1 through 7 were performed with unit conditions closely approximating those of Baseline Tests 1 - 7 under Program Task IV. A clean furnace was maintained as the excess air was varied at three unit loads.

The effect of these operating conditions on emission levels and performance can be seen in the Table above.

As witnessed in the previous baseline tests, NO_x emissions levels increased with increased excess air.*

---

* In general, NO_2 values were slightly lower after modification for the same test conditions. This resulted from an updated firing system installed between the sets of tests along with an average percent nitrogen in fuel decrease of 0.15 percent (1.21 to 1.06 percent). Also, fuel higher heating values and furnace outlet temperatures tended to be lower for Tests 1 - 7 after modification.

ID fan capacities limited excess air to a maximum of 64.7 and 33.5 percent at half and full load conditions respectively. Acceptable minimum excess air limits were established at 20-25 percent to control CO emission levels. Thus, NO_x emission levels could only be reduced to approximately 0.90 g/10^6cal through excess air reduction. The effect of theoretical air to the firing zone on NO_x, CO, and percent carbon loss in the fly ash (% CL) can be seen in Figures 17, 18 and 19. In agreement with the original baseline tests, theoretical air to the firing zone (TA) was used for comparison in place of total excess air (EA). TA is determined by location and means of admission as well as quantity, and consequently better defines that air actually available for initial combustion.

Figure 17 indicates a definite increase in NO_x emission levels with increasing TA for clean furnace conditions. CO emission levels and percent carbon loss in the fly ash can be seen to increase with decreased TA without overfire air. Reasonable control of CO and % CL can only be maintained at TA levels above 120%. No definite relationship can be observed between unit load and CO emission levels. Percent CL can be seen to be greater at higher unit loads for given TA levels.

Changes in unit efficiency versus excess air at the economizer outlet are presented in Figure 20. Overall, unit efficiency decreases as the excess air increases.

Hydrocarbon emission levels appeared only in trace quantities for this portion of the test program. HC and SO_2 levels are presented on Data Sheets 3 and 4.

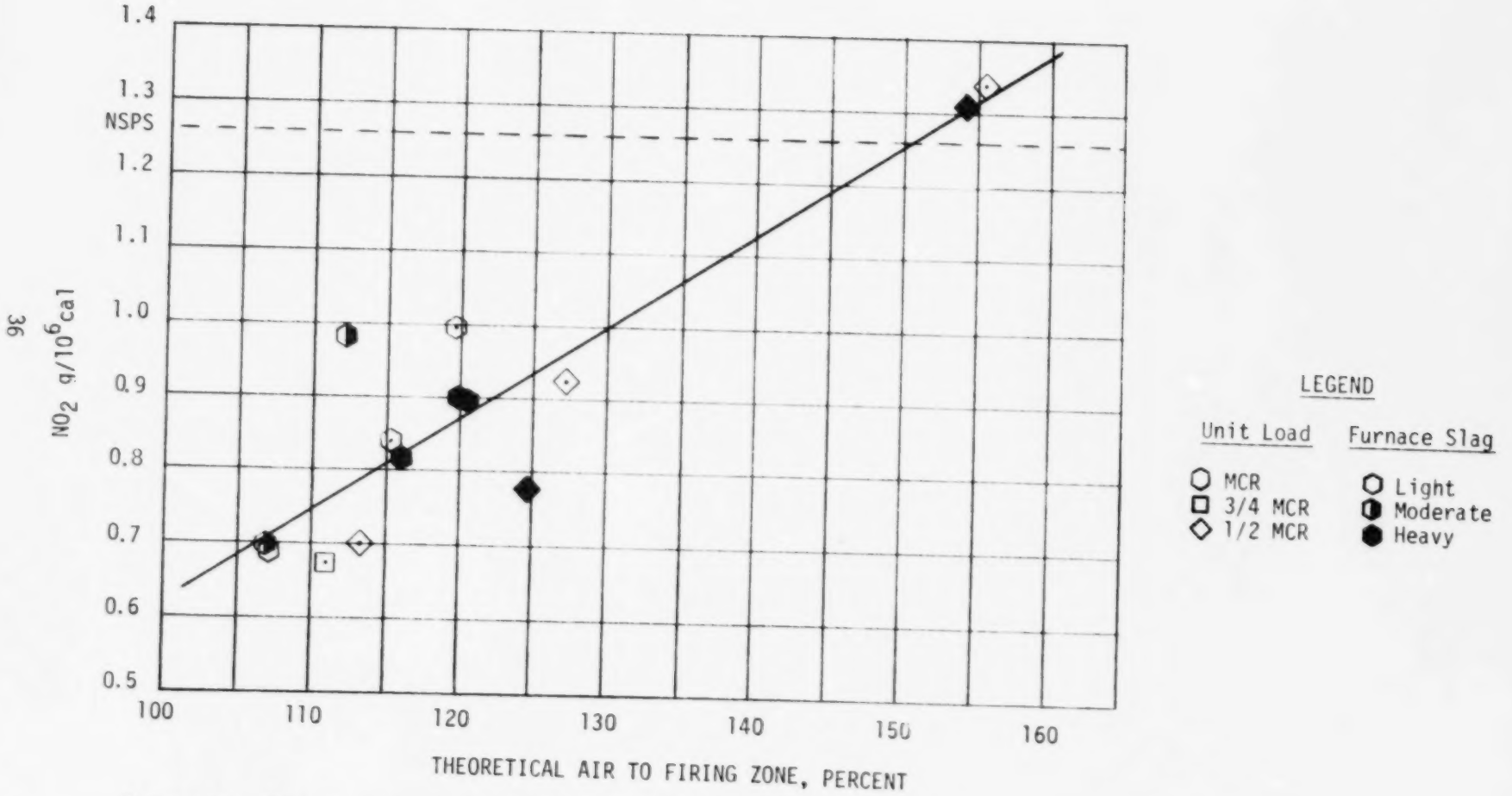


Figure 17: NO_2 Vs. Theoretical Air to Firing Zone, Overfire Air Study, Load and Excess Air Variation, Tests 1-14

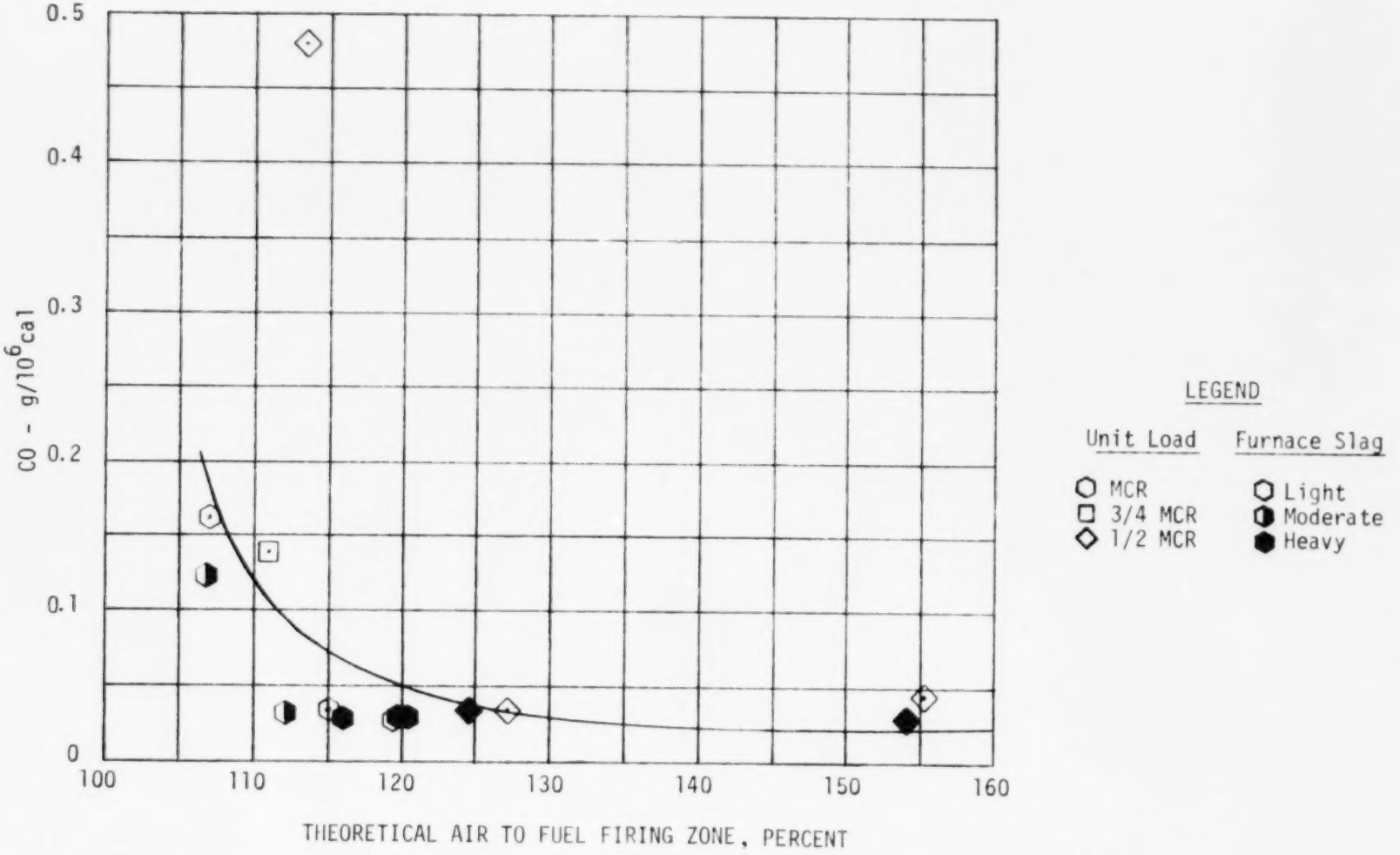


Figure 18: CO Vs. Theoretical Air to Firing Zone, Overfire Air Study, Load and Excess Air Variation, Tests 1-14

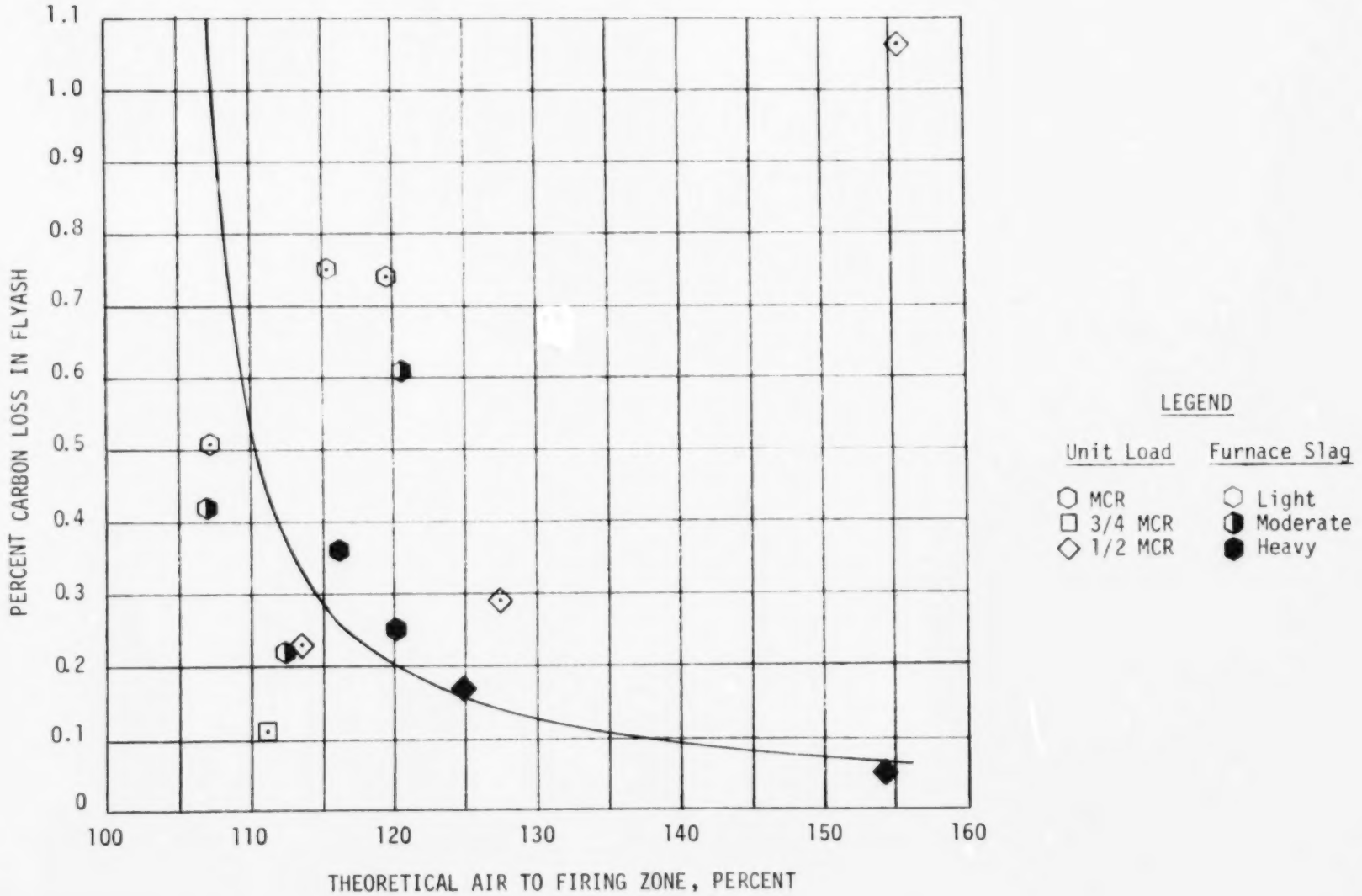


Figure 19: Percent Carbon Loss Vs. Theoretical Air to Firing Zone, Overfire Air Study Load and Excess Air Variation, Tests 1-14

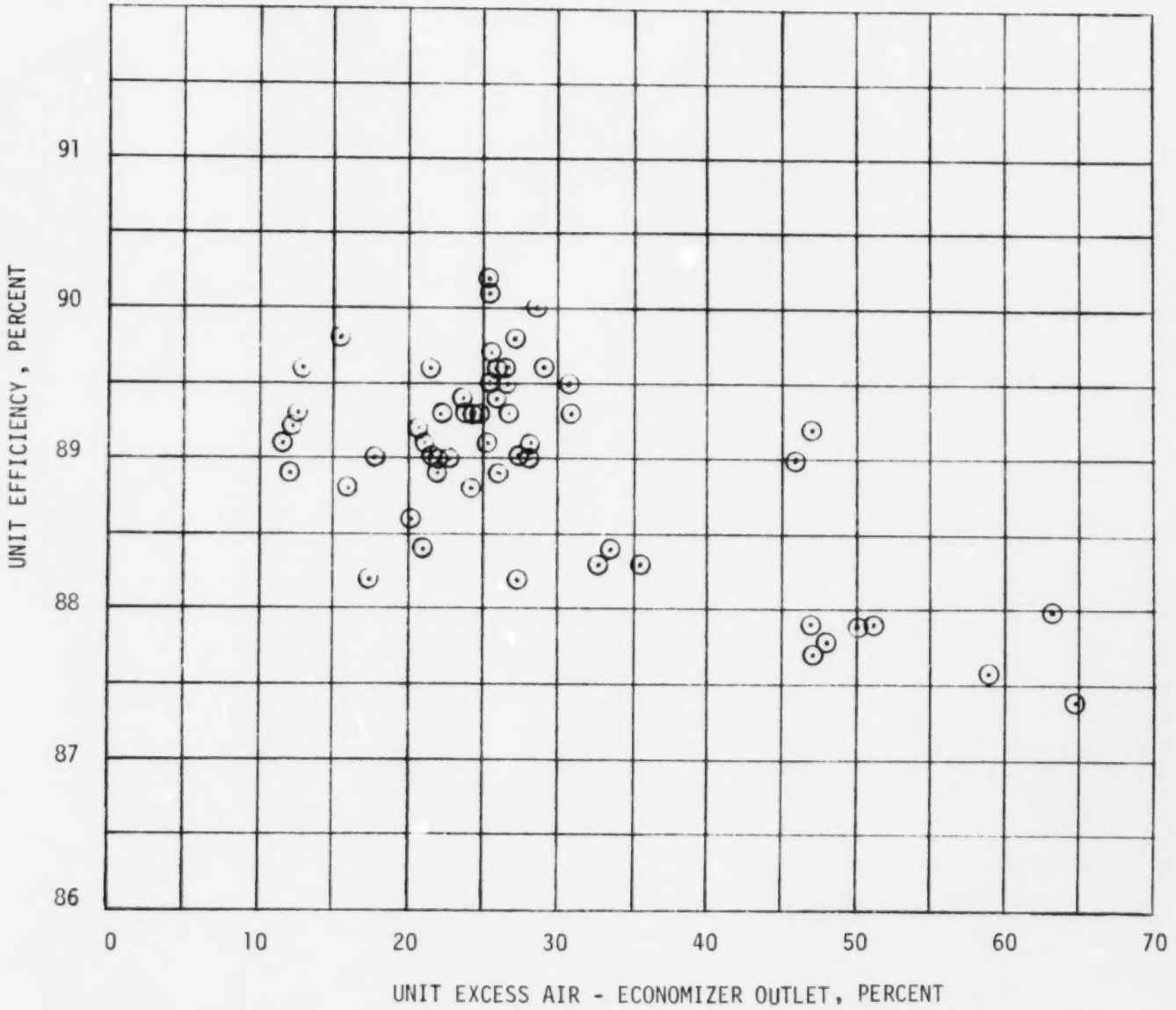


Figure 20: Unit Efficiency Vs. Excess Air - Economizer Outlet, All Tests (Before & After Modification)

Furnace Wall Deposit Variation (After Modification)

Test No.	Main Steam Flow 10^3 kg/hr	NO_2 g/10^6 cal	CO g/10^6 cal	EA %	Theo. Air Firing Zone %	Unit Eff. %	WW Slag
8	440	0.985	0.0310	17.8	112.3	89.0	1/2 Max
9	446	0.699	0.1239	12.1	106.9	88.9	1/2 Max
10	428	0.902	0.0300	26.6	120.5	89.5	1/2 Max
11	246	0.782	0.0335	30.9	124.6	89.3	Max
12	218	1.310	0.0304	63.1	154.0	88.0	Max
13	432	0.819	0.0298	22.0	116.2	89.0	Max
14	425	0.902	0.0292	25.9	119.9	89.4	Max

The effect of furnace waterwall deposits on unit performance and emission levels was studied in Tests 8 through 14 (Clean Condition - Maximum Slagging Conditions). Dirty conditions were established after a minimum of 24 hours of no operation of wall blowers. Deposits of up to four inches in thickness could subsequently be found in and above the fuel firing zone.

Figures 17, 18 and 19 reveal no observable effect of furnace cleanliness on NO_x or CO emission levels along with percent carbon loss in the fly ash.*

Slag patterns taken during full load operation for clean, moderate and heavy slagging furnace conditions can be viewed in Figures 21, 22 and 23.

---

* Again, NO_x values were generally slightly lower after modification. Nitrogen in fuel decreased an average of 0.19 percent from 1.23 percent. Furnace outlet temperatures were somewhat lower for Tests 8 through 14 after modification although fuel higher heating values showed no definite change.

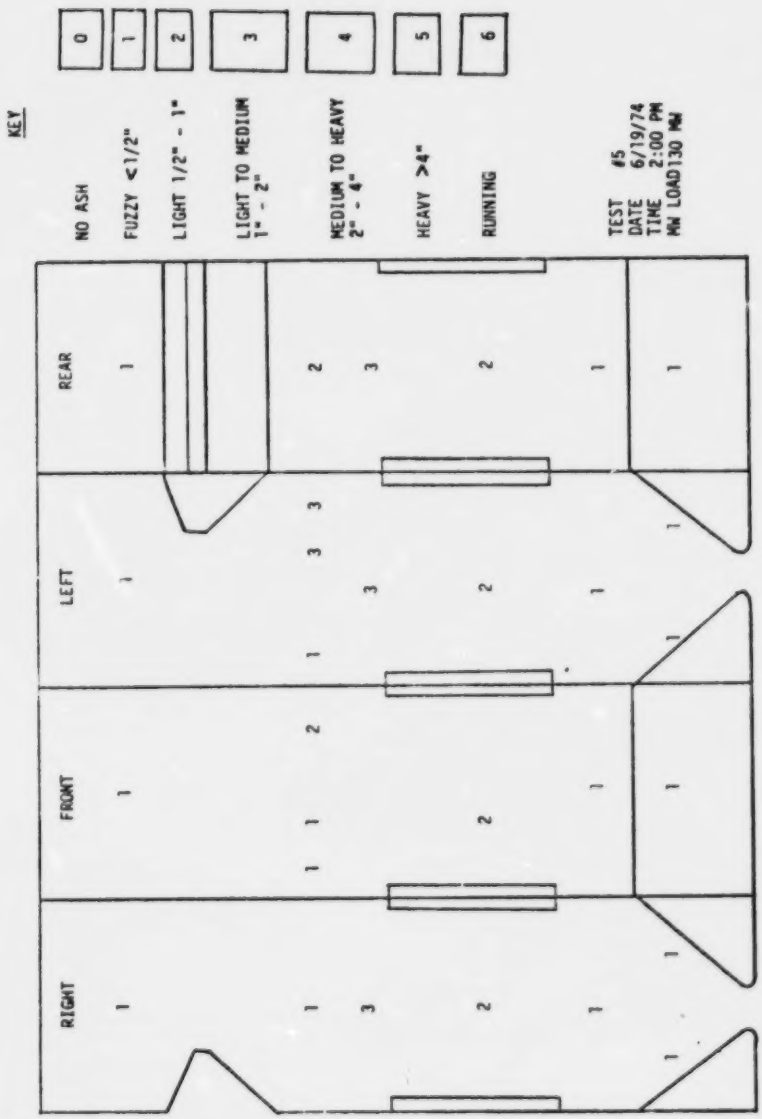


Figure 21: Furnace Slag Pattern, Clean Furnace

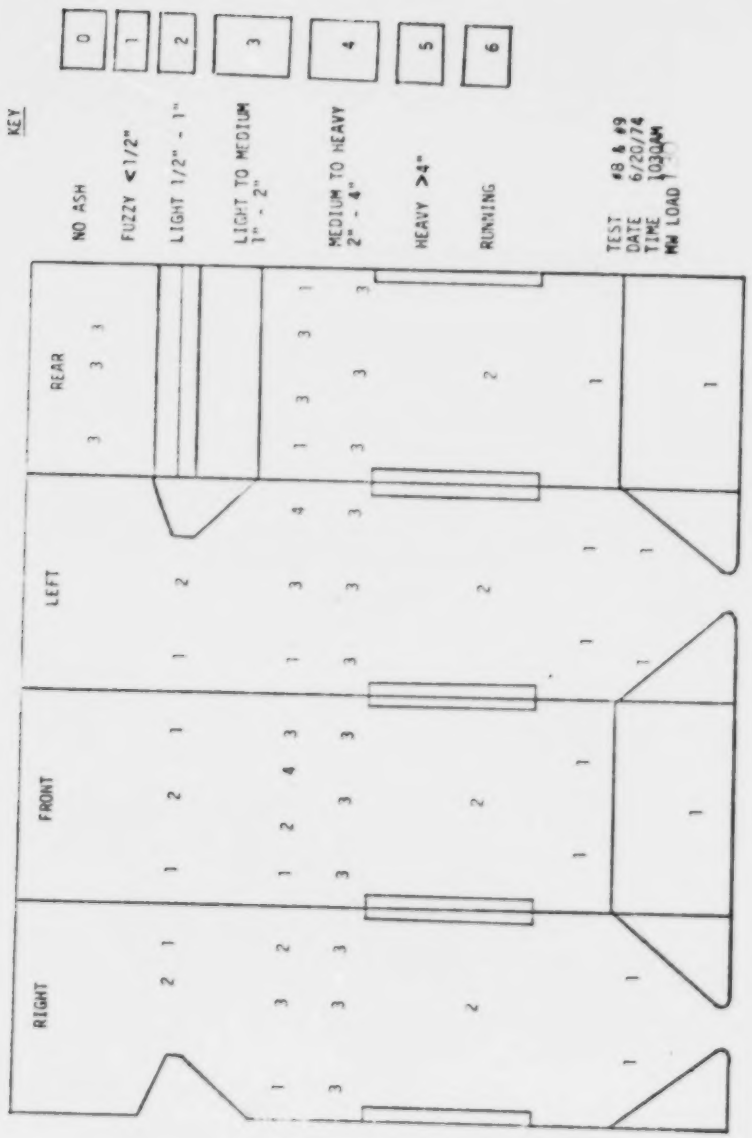


Figure 22: Furnace Slag Pattern, Moderate Slag Furnace

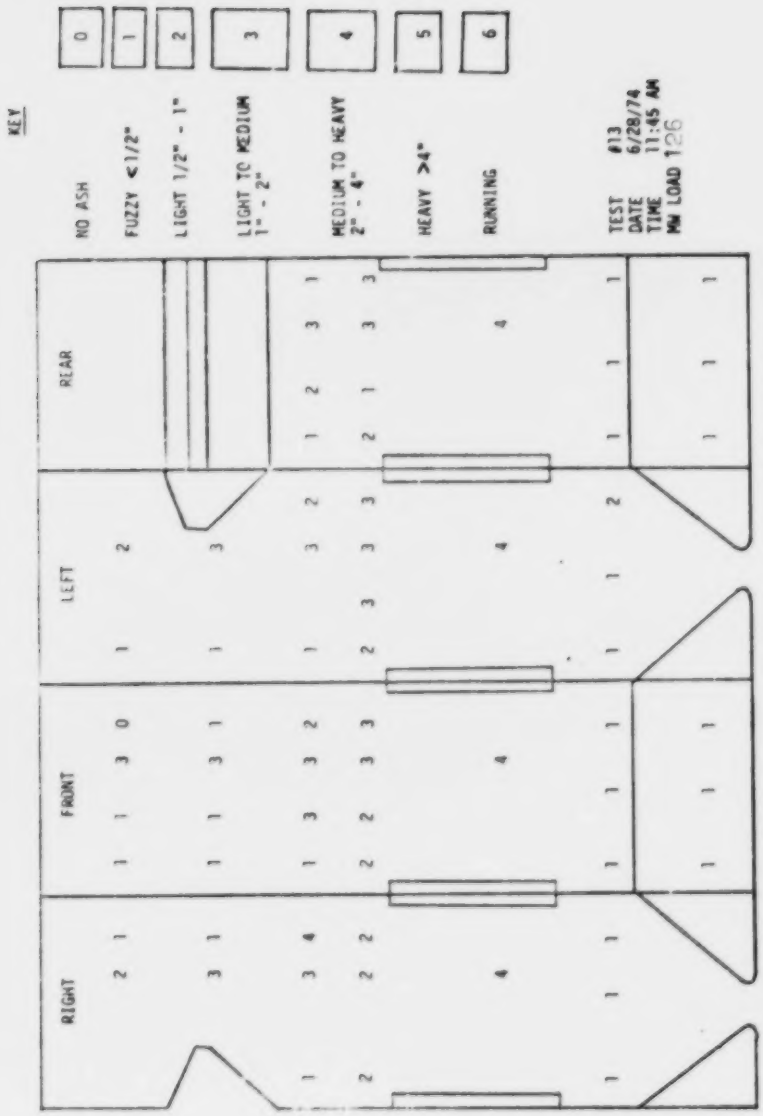


Figure 23: Furnace Slag Pattern, Heavy Slag Furnace

This set of tests also confirms the results found in Tests 1 through 7. NO_x emission levels increase with increased excess air. NO_x cannot be decreased through excess air reductions below 20 percent excess air while maintaining an acceptable CO emission level without overfire air.

OFA Location, Rate, and Velocity Variation

Test No.	Main Steam Flow 10^3 kg/hr	NO_2 g/10^6 cal	CO g/10^6 cal	Theo. Air Firing Zone %	Unit Eff. %	Mills In Serv.	Adm. Pts.*	Adm. Rate
15	336	0.723	0.0358	114.5	90.0	BCD	0-1	0
16	340	0.533	0.0382	96.7	89.8	BCD	0-1	Max
17	338	0.533	0.0413	95.8	89.7	BCD	0-2	Max
18	344	0.479	0.0613	84.8	89.6	BCD	0-1,0-2	Max
19	338	0.486	0.0500	89.3	89.3	BCD	0-1,0-2	1/2 Max
20	344	0.677	0.0367	100.5	90.2	BCD	0-3	Max
21	342	1.012	0.0321	117.4	90.1	ABC	0-1	0
22	341	0.689	0.0329	90.4	89.0	ABC	0-1,0-2	Max
23	346	0.704	0.0322	96.9	89.1	ABC	0-1,0-2	1/2 Max

Tests 15 through 23 were performed to establish the effect of overfire air admission on NO_x emission levels. The unit load and excess air remained constant for moderately dirty furnace conditions. Location of air admission to the furnace was varied.

As shown in Figure 24, this set of tests shows a tendency of NO_x emission levels to decrease with decreased theoretical air to the firing

---

* OFA Admission Points:

O-1: Top overfire air compartment.

O-2: Bottom overfire air compartment.

O-3: Top fuel elevation out of service.

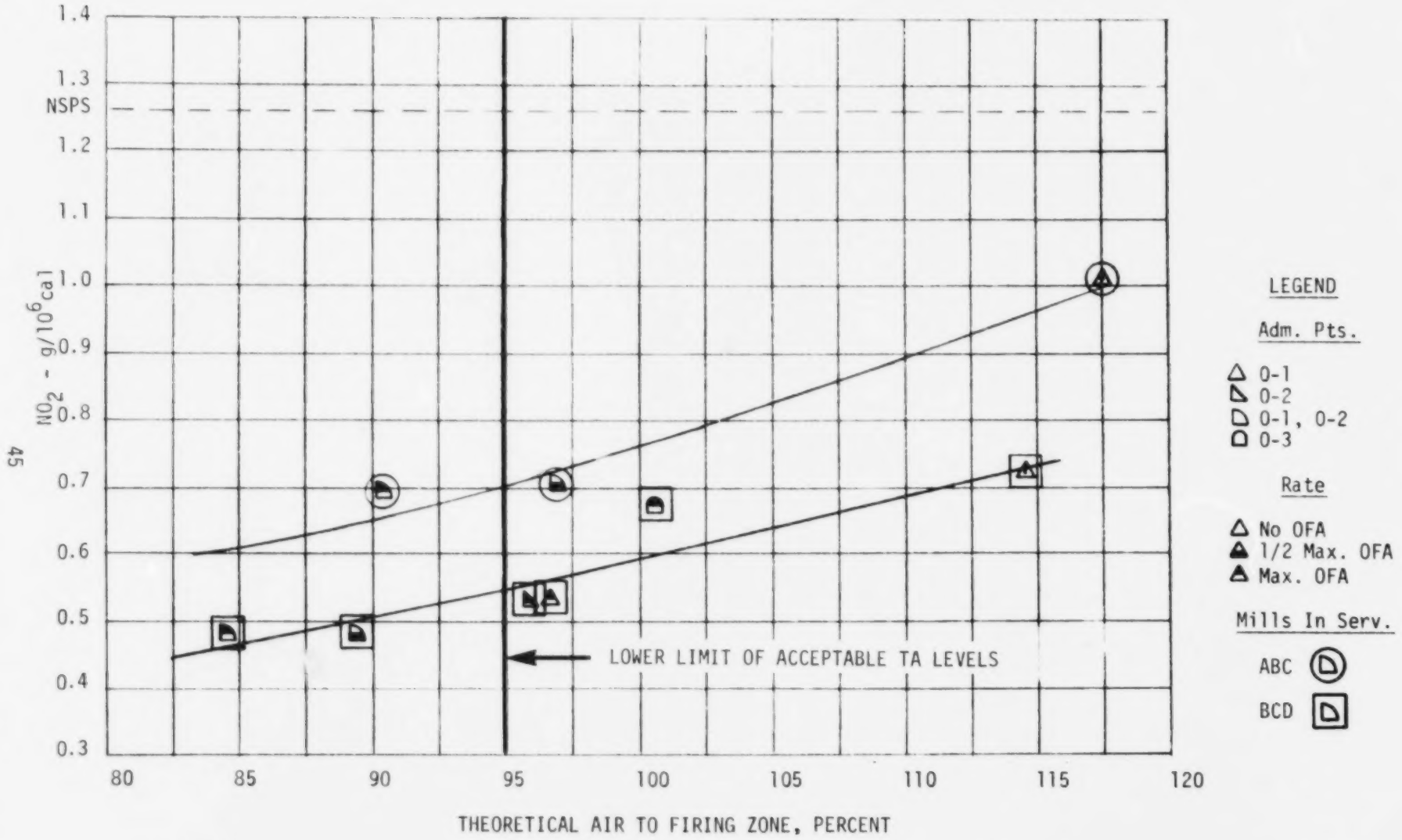


Figure 24: NO_2 Vs. Theoretical Air to Firing Zone, Overfire Air Location, Rate & Velocity Variation, Tests 15-23

zone. NO_x levels are generally higher with ABC mills (top 3 elevations) in service than with BCD mills (bottom 3 elevations). Both operating conditions support the premise of reducing NO_x emission levels by reducing the air input to the fuel firing zone and admitting downstream of that point. The fire is thereby spread out over more of the furnace reducing its intensity. The above factors are limited by flame stability which became very lazy in Test 18. By using the bottom 3 elevations in place of the top 3 elevations, the distance between the overfire air and the firing zone was increased. (The mean firing elevation is also slightly decreased.) Comparison of Tests 18 and 19 with Tests 22 and 23 reveals lower NO_x levels obtained with increased distance between the overfire air and the firing zone. Operation at TA levels below 95% did not result in significant reductions in NO_x emission levels.

CO emission levels remained acceptable for the entire set of tests where the total excess air was approximately 27 percent as shown on Figure 25.

OFA admission location or rate variation exhibited no significant change in percent carbon loss in the fly ash as shown on Figure 26.

Unit efficiencies were not significantly affected by fuel elevations in service, or by overfire air location and rate variation. This is explained by the fact that essentially constant total excess air levels were maintained during this study.

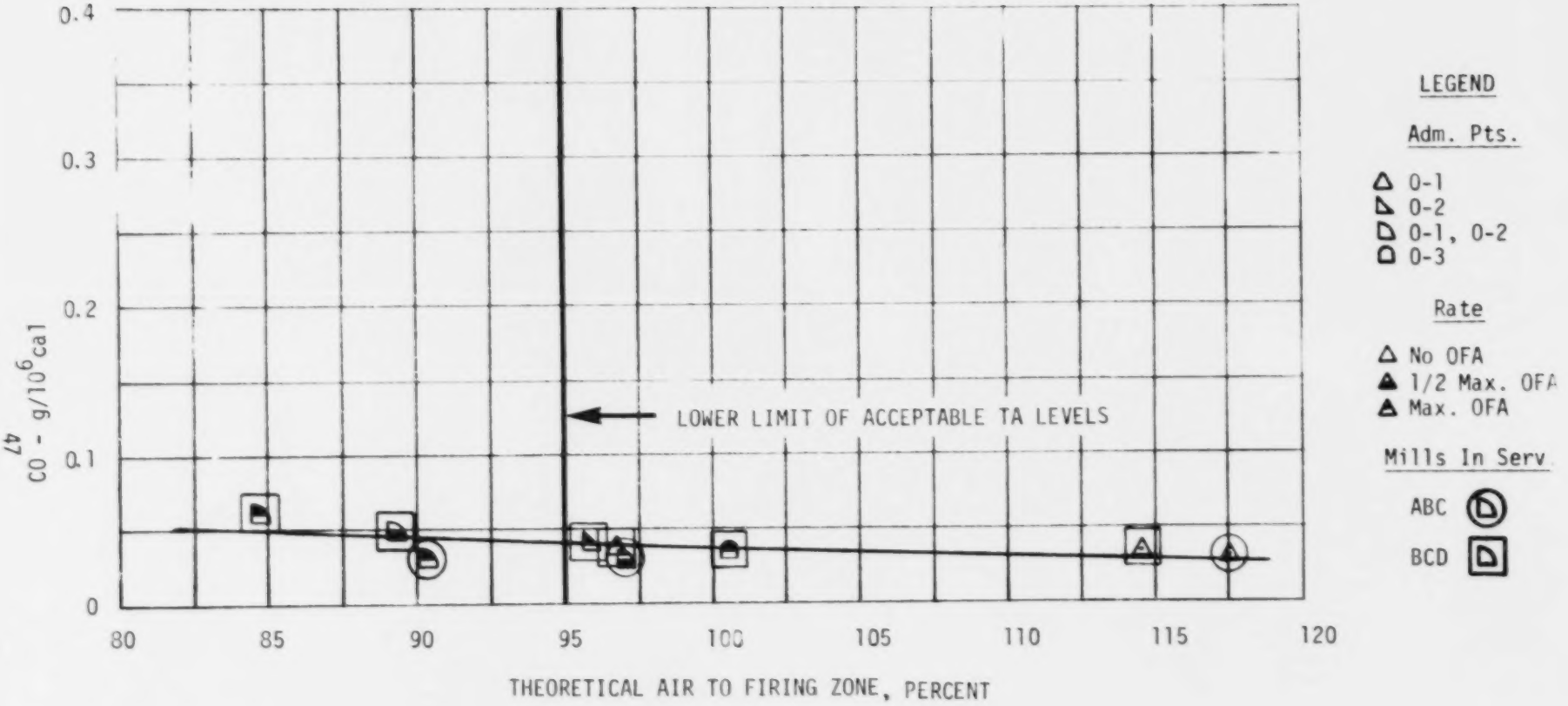


Figure 25: CO Vs. Theoretical Air to Firing Zone, Overfire Air Location, Rate & Velocity Variation, Tests 15-23

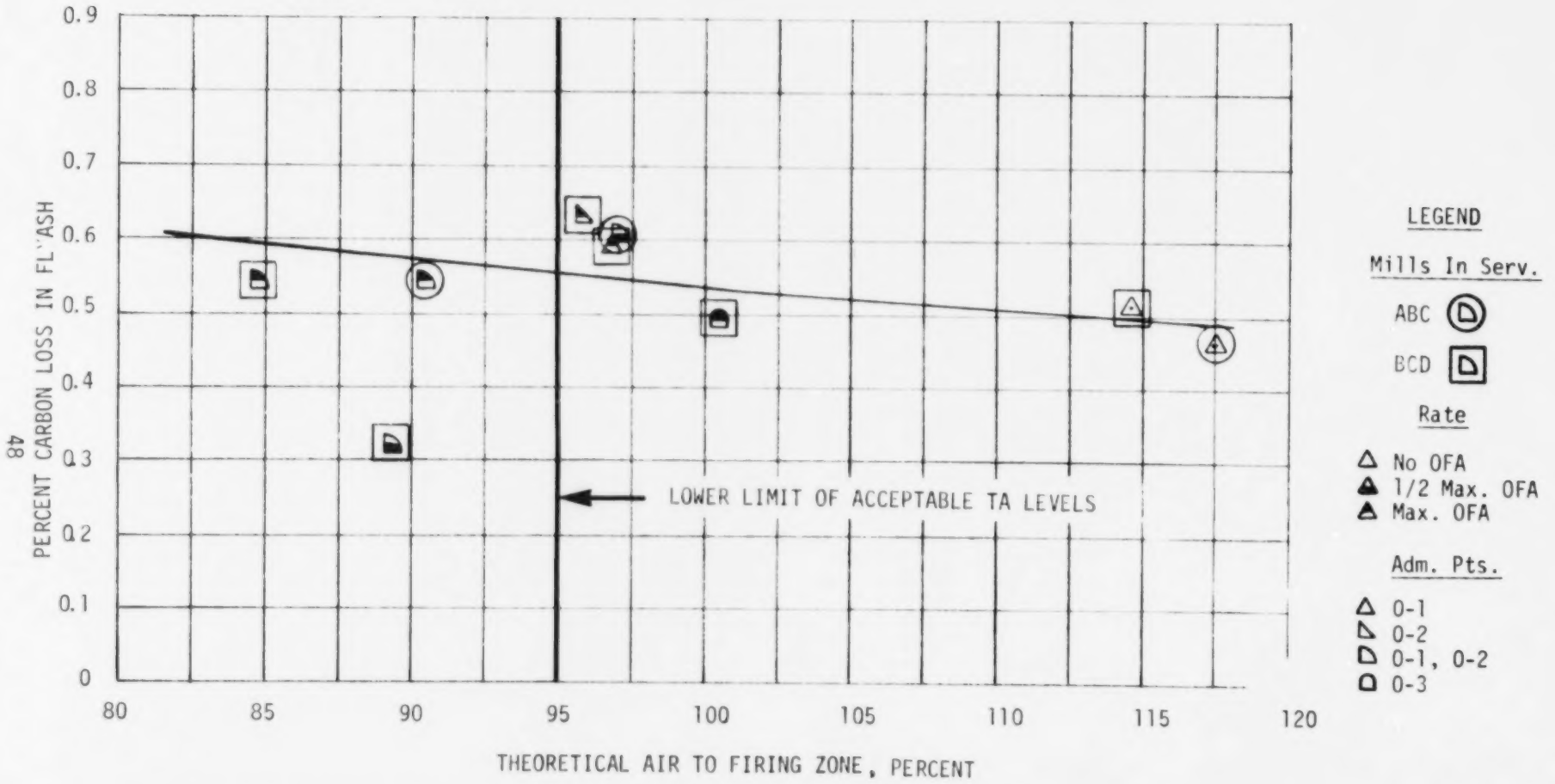


Figure 26: Percent Carbon Loss Vs. Theoretical Air to Firing Zone, Overfire Air Location Rate & Velocity Variation, Tests 15-23

OFA Tilt Variation

Test No.	Main Steam Flow 10^3 kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air Firing Zone %	Unit Eff. %	Fuel Nozz Tilt °	OFA Tilts °
24	407	0.710	0.0324	25.9	94.2	89.6	-5	0
25	418	0.609	0.0346	23.7	92.4	89.3	-23	0
26	412	0.770	0.0406	25.1	93.2	88.9	+19	0
27	407	0.721	0.0282	22.3	91.5	89.3	-5	-30
28	414	0.846	0.0360	20.2	89.6	88.6	+22	-30
29	418	0.596	0.0630	23.7	92.6	89.4	-21	+30
30	416	0.710	0.0333	21.6	90.7	89.0	-4	0
33	409	0.697	0.0316	27.4	94.6	89.0	-22	-22

Tests 24 through 30, and 33, were conducted at full unit load with excess air and theoretical air levels to the firing zone of approximately 24 percent and 92 percent, respectively. With moderate slagging conditions on the waterwalls the fuel nozzle tilts and OFA tilts were varied. This essentially moves the firing zone both in the furnace and in its relative position to the overfire air. Fuel nozzle tilts that are maximum minus combined with OFA tilts of maximum plus increase the distance between the overfire air and the firing zone. As with previous methods of increasing this distance, the NO_x emission levels are decreased. Figure 27 shows that as the tilts are moved toward one another (fuel nozzle tilts up; OFA tilts down), the OFA - firing zone separation is decreased and the NO_x levels are increased.

When the OFA tilts are maximum minus and the fuel nozzle tilts maximum plus, the term overfire air becomes ambiguous. The actual overfire air is less than the reported value, because the air is being forced down into the raised firing zone. At this point where the combined fuel nozzle and OFA tilt differential is 52 degrees toward each other, the NO_x emission level reacnes a maximum of 0.846 g/10^6cal.

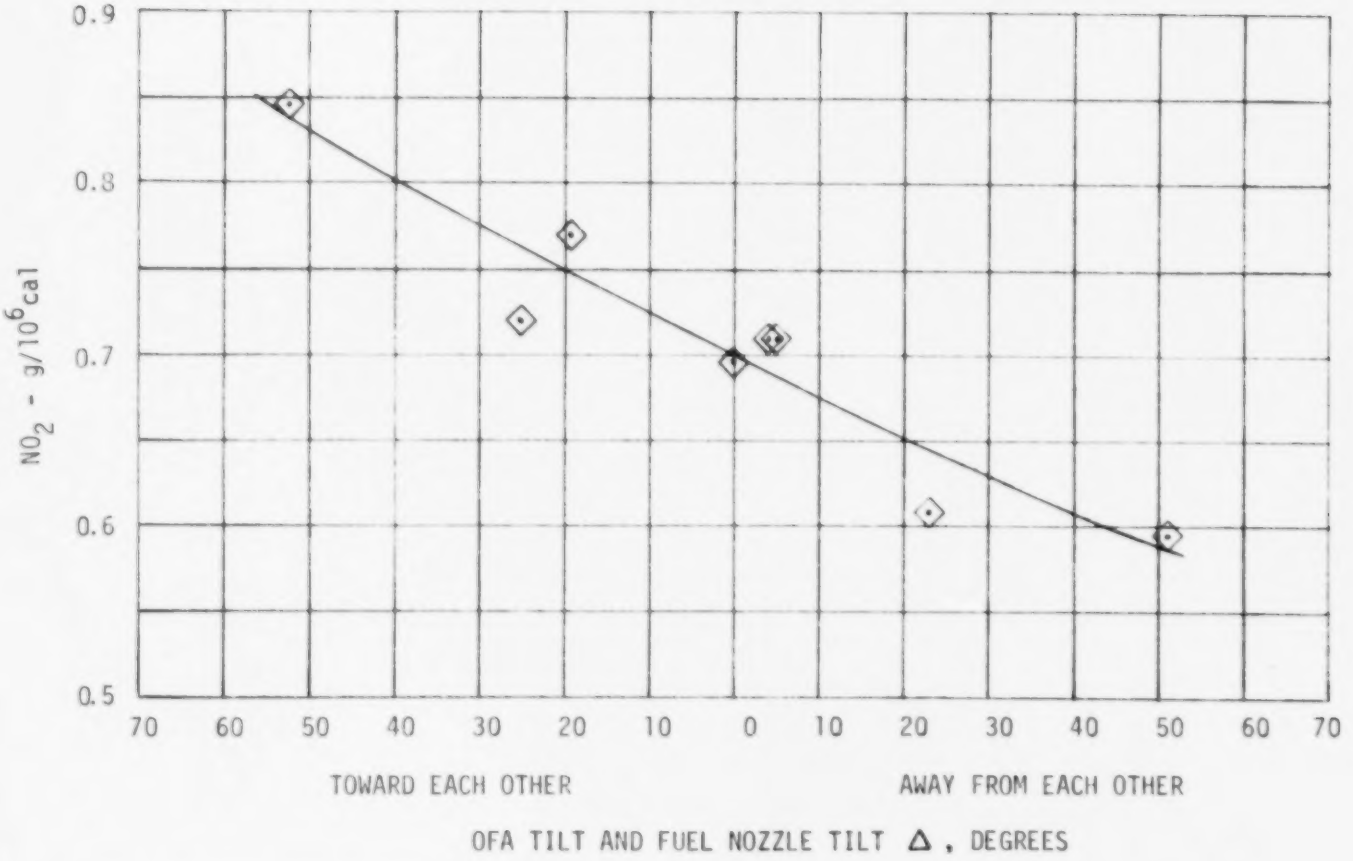


Figure 27: NC_2 Vs. OFA Tilt and Fuel Nozzle Tilt Differential, OFA Tilt Variation Tests 24-33

Percent carbon loss in the flyash exhibits a definite increase as the fuel nozzle tilts and OFA tilts move away from each other. This can be witnessed in Figure 28.

CO emission levels also show an increase as the tilt differential increases, yet there is enough total excess air to maintain an acceptable emission level as shown in Figure 29.

Flame stability arises as a limiting factor in variation of the tilts. As the tilts move substantially away from each other, the fire becomes unstable and pulsing may result. Test 29 was performed with a fuel nozzle and OFA tilt differential of 51 degrees away from each other. NO_x emission levels decreased to 0.596 g/10^6cal, yet the CO emission levels began to increase and the fire appeared less stable. Maintaining the fuel nozzle tilts and OFA tilts at approximately equal tilt angles resulted in acceptable flame stability as well as reduced NO_x emission levels.

For all OFA tilt variation tests the NO_x emissions level obtained was below the EPA limit of 1.26 g/10^6cal.

Load Variation at Optimum Conditions

Tests 30 through 35 were conducted to evaluate unit performance and emission levels at optimum operating conditions as determined during Tests 15 through 29. Tests were conducted over the unit load range at varying furnace waterwall slagging conditions. The NO_x emission level results of this series of tests versus unit loading, expressed as main steam flow, are shown on Figure 30.

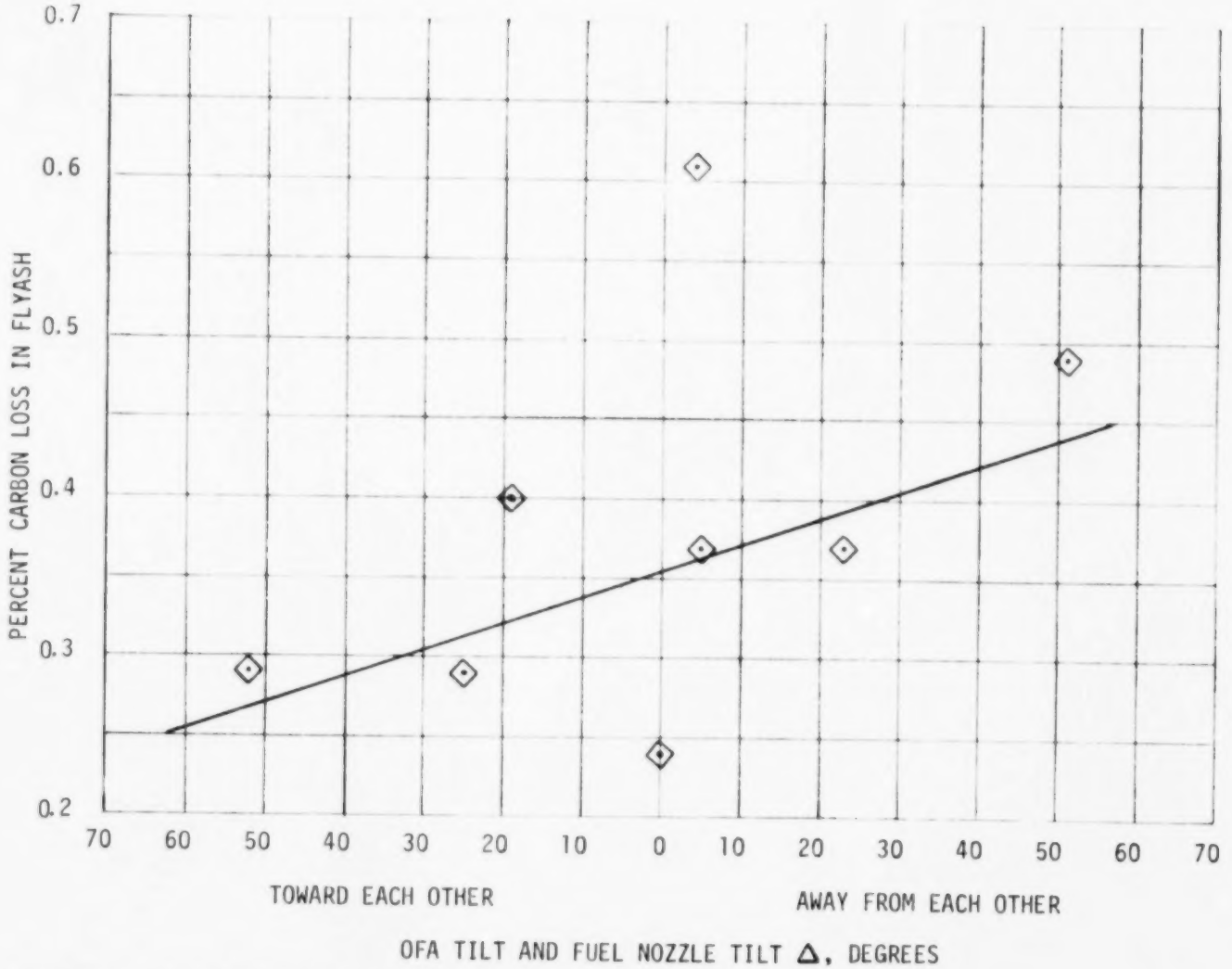


Figure 28: Percent Carbon Loss Vs. OFA Tilt and Fuel Nozzle Tilt Differential, OFA Tilt Variation, Tests 24-33

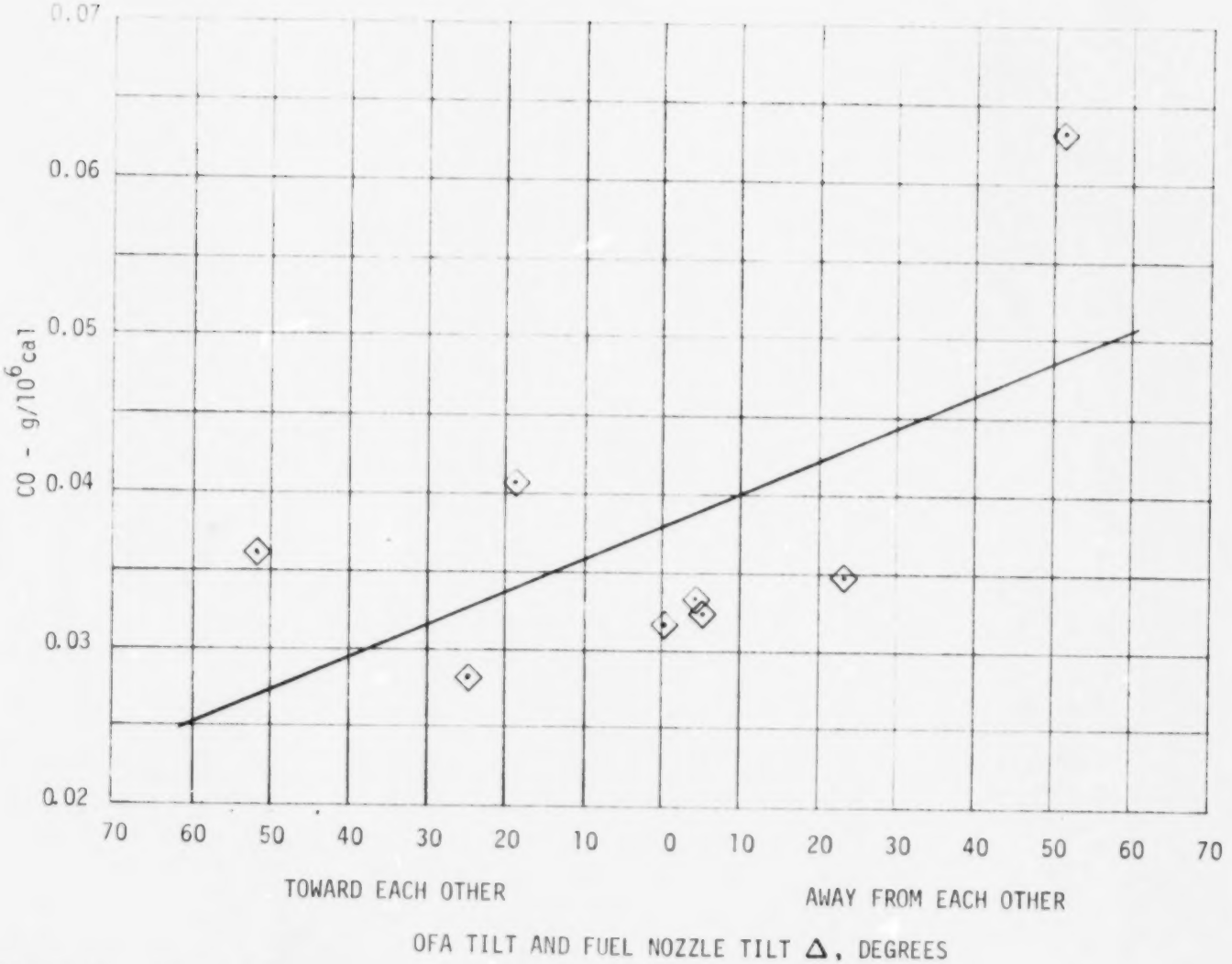


Figure 29: CO Vs. OFA tilt and Fuel Nozzle Tilt Differential, OFA Tilt Variation Tests 24-33

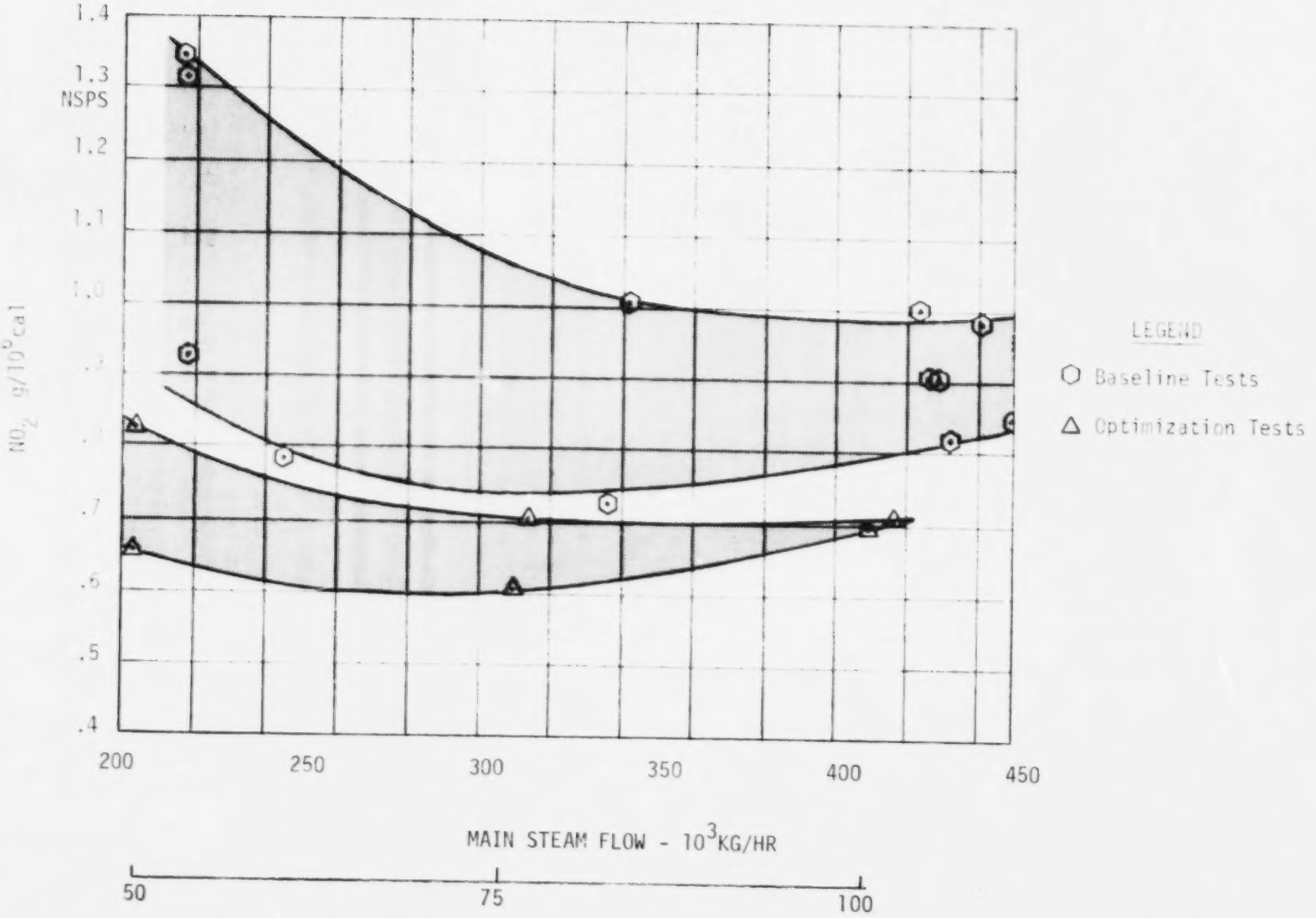


Figure 30: NO_2 Vs. Main Steam Flow, Ranges for Normal & Optimum Operation

Load Variation at Optimum Conditions

Test No.	Main Steam Flow 10^3kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air Firing Zone %	Unit Eff. %	WW Slag
30	416	0.710	0.033	21.6	90.7	89.0	Clean
31	314	0.708	0.033	25.2	89.4	89.1	Clean
32	204	0.828	0.031	46.9	88.5	89.2	Clean
33	409	0.697	0.032	27.4	94.6	89.0	Max.
34	310	0.608	0.034	27.4	90.6	88.2	Max.
35	204	0.655	0.032	45.9	88.5	89.0	Max.

This figure illustrates the range of NO_2 levels obtained both during baseline (after modification) and optimum unit operations. Not all the baseline tests are included as in some cases unit operation was felt to depart excessively from normal operations. Low excess air operation can be cited as an example.

The wide range of NO_2 levels obtained, particularly during the baseline tests are due to variations in unit operating parameters such as excess air level. During the optimization tests total excess air at the unit economizer outlet was maintained between 20 and 28% at full and 3/4 load and 45 to 47% at 1/2 load and fuel nozzle tilts raised or lowered as required to maintain acceptable reheat and superheat outlet temperatures. Also minimum excess air levels were established on the basis of maintaining acceptable CO emission levels and flame stability.

Tests 30, 31 and 32 were conducted as a series and no problems were encountered while changing load with optimum operation.

Furnace Performance

During the test program furnace performance was monitored by use of chordal thermocouples installed in the furnace waterwalls. A schematic of the thermocouple locations is shown in Figure 31 and a tabulation of

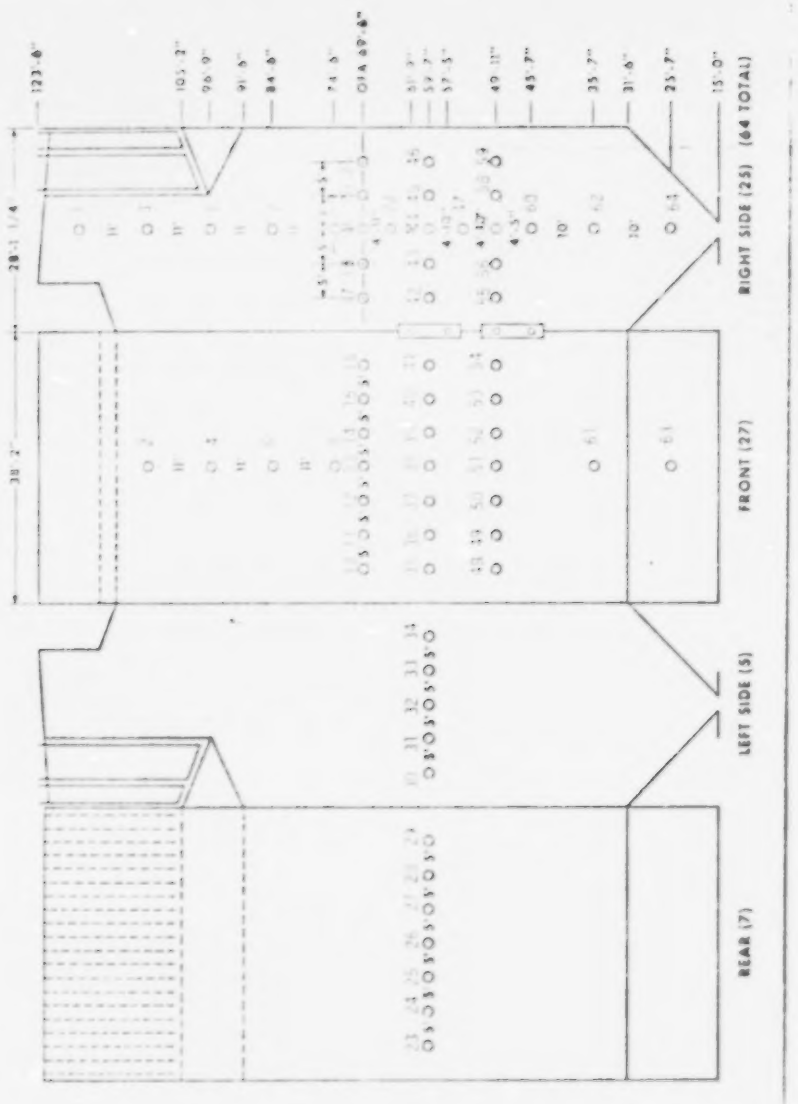


Figure 31: Chordal Thermocouple Locations on the Furnace Waterwalls

the absorption rates obtained is presented on Sheets 13A, 13B and 13C. The temperatures and corresponding absorption rates were found to vary significantly with wall slag conditions making data interpretation difficult. The method finally arrived at as representing an accurate indication of furnace performance is as follows:

The front and right side wall centertube profiles were plotted as shown in Figure 32 and the average of these profiles determined. It should be noted that the maximum and minimum profiles shown do not represent individual walls in every case, i.e., at given furnace elevations the maximum rate shown may switch from wall to wall.

For comparison of optimum and normal unit operation with respect to furnace performance, three full load tests with similar furnace slagging conditions, etc., were selected for comparison. The average centerline profiles for these tests (14, 24, 33) were determined, as shown on Figures 32, 33 and 34, and then plotted together as shown on Figure 35. As shown, furnace performance remained essentially unchanged when furnace slagging effects are taken into account.

It should be noted here that obtaining desired slag conditions proved to be difficult and somewhat unpredictable during overfire air operation. This situation was most pronounced in the firing zone where slag accumulations would normally shed themselves before appreciable accumulations could be built up.

Waterwall Corrosion Coupon Evaluation

Following completion of the steady state phases of the baseline, biased firing and overfire air test programs, thirty (30) day waterwall corrosion coupon evaluations were performed. The purpose of these evaluations was to determine whether any measurable changes in coupon weight losses could be obtained for the various firing modes studied.

The corrosion probes used in the evaluations were previously shown on

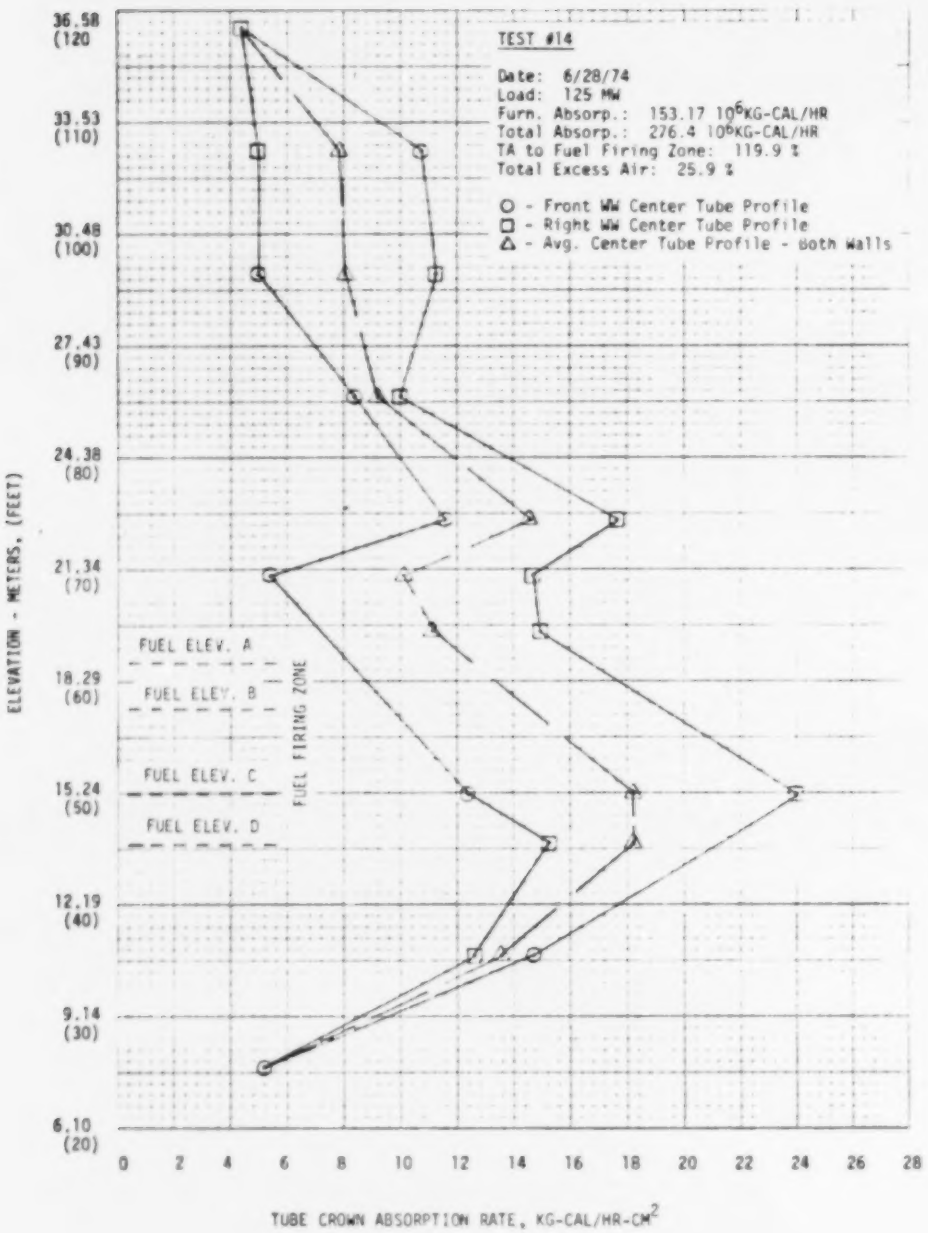


Figure 32: Average Centerline Absorption Profile, Test 14

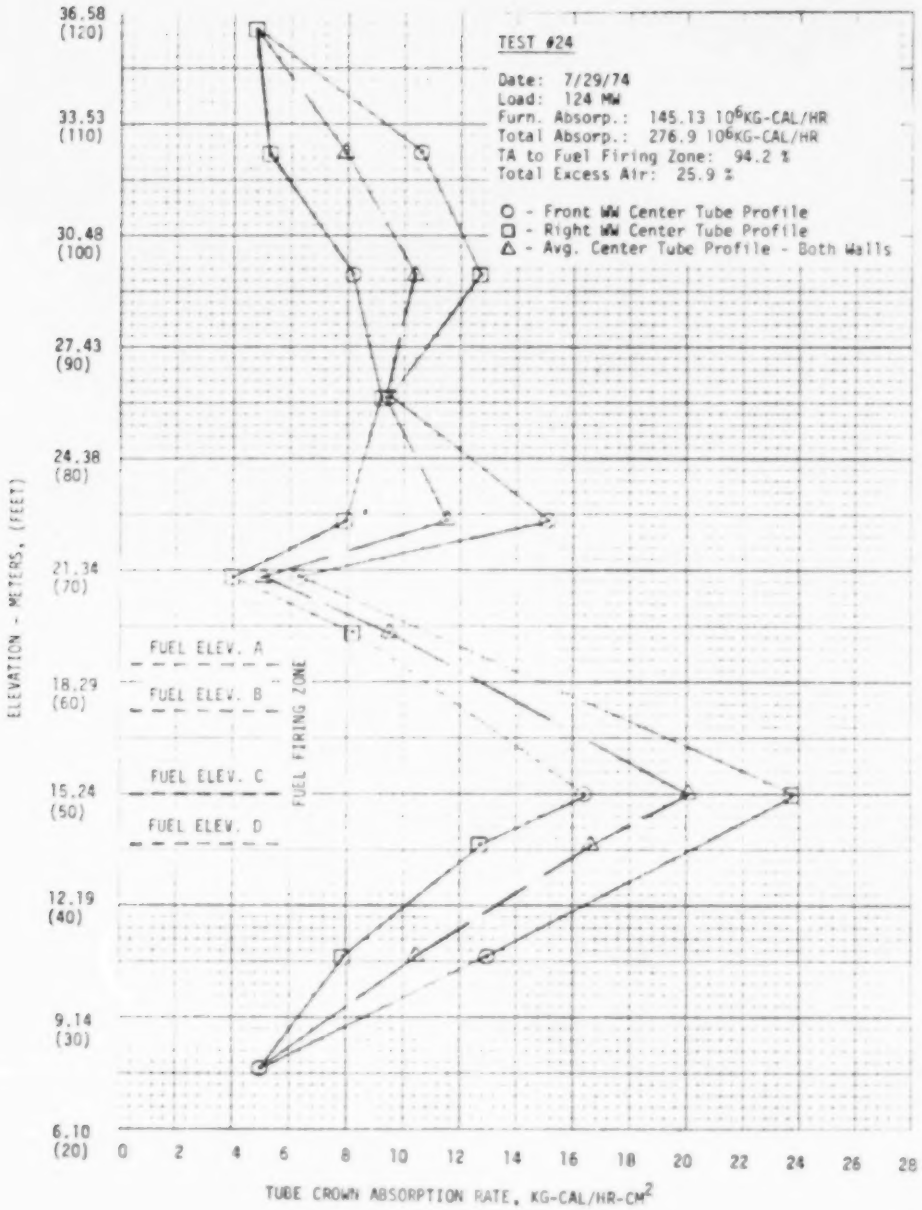


Figure 33: Average Centerline Absorption Profile, Test 24

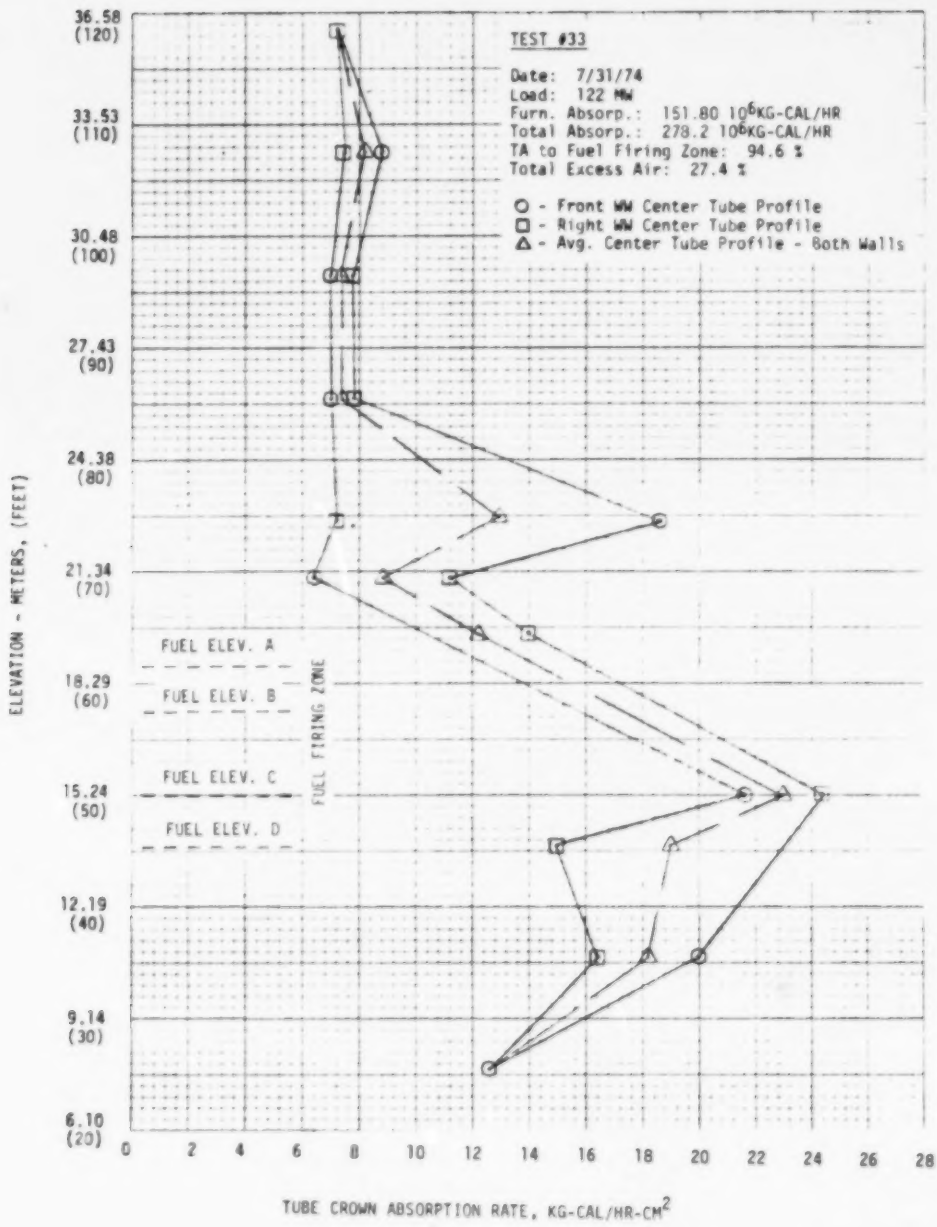


Figure 34: Average Centerline Absorption Profile, Test 33

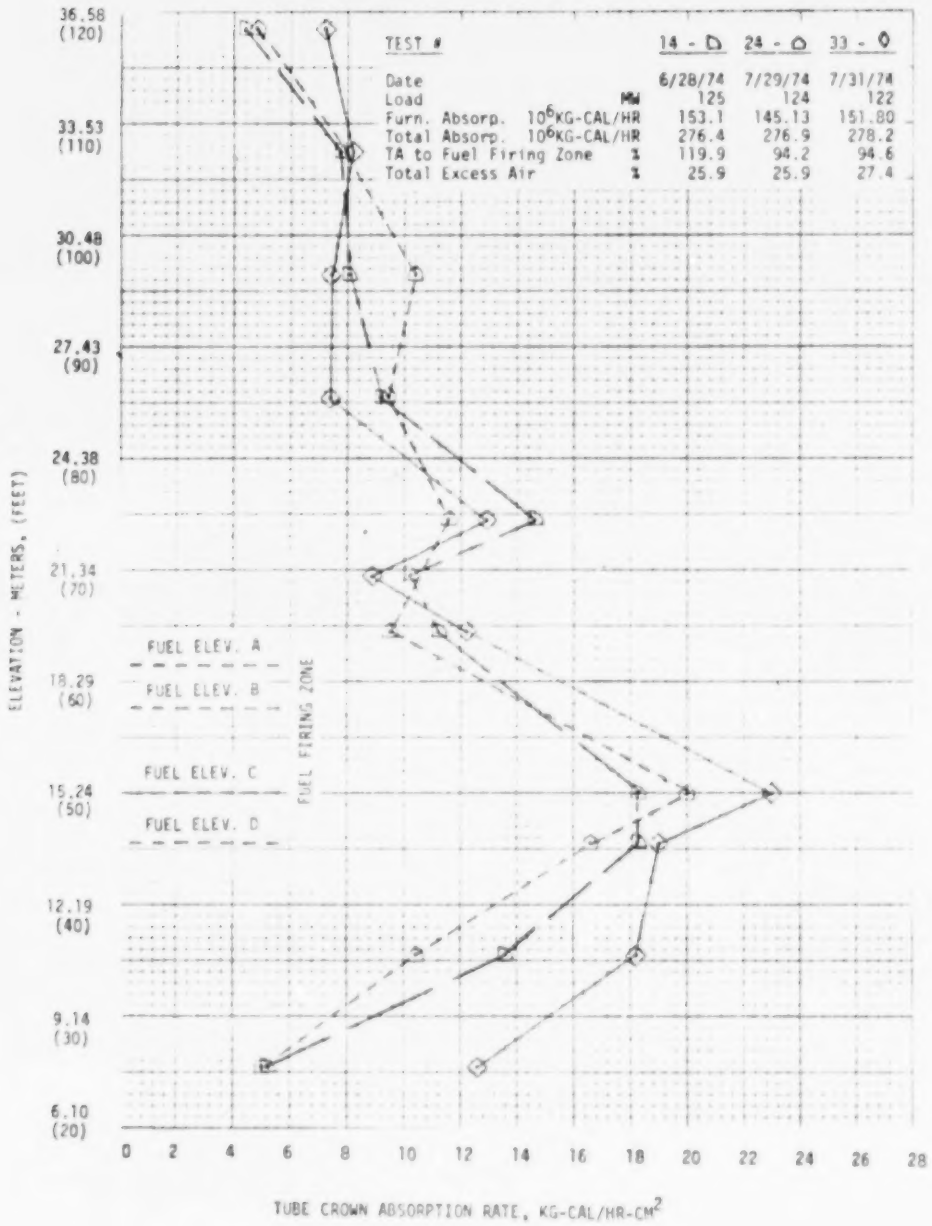


Figure 35: Average Centerline Absorption Profile, All Tests

Figure 4. The individual probes were exposed at five locations on the furnace front wall as shown on Figure 5. The coupon temperatures were maintained at the same levels for each 30 day run and a typical trace of the control temperature range for each of the twenty coupons is shown on Figure 6.

The individual coupon weights were determined before and after each thirty day test and the individual coupon and average probe weight losses are shown on Sheets 14A, 14B, and 14C. The weight losses are calculated as mg/cm^2 of coupon surface area. Of the sixty coupons exposed, three were damaged during disassembly and were therefore not included in the weight loss determinations. The affected coupons were as follows: Coupon K-1, baseline study, and coupons 2-1 and 2-4 overfire air study. In addition, five coupons from probes T and N of the overfire air study resisted disassembly and were therefore weighed as single units and average weight losses were determined.

Figures 36, 37 and 38 show the unit load schedules for each of the 30 day test periods.

The biased firing study was conducted with the top fuel firing elevation out of service as this operating condition was shown during steady state biased firing tests to produce the lowest NO_x emission level of the biasing modes studied. The overfire air study was conducted using an "optimized" operating mode as determined during the overfire air steady state tests.

Throughout each study the following damper positions were maintained over the load ranges indicated.

At unit loadings below 204,000 kg/hr steam flow, with two elevations of mills in service, damper positions were maintained as follows:

Figure 36: Gross MW Loading Vs. Time - Baseline Corrosion Probe Study

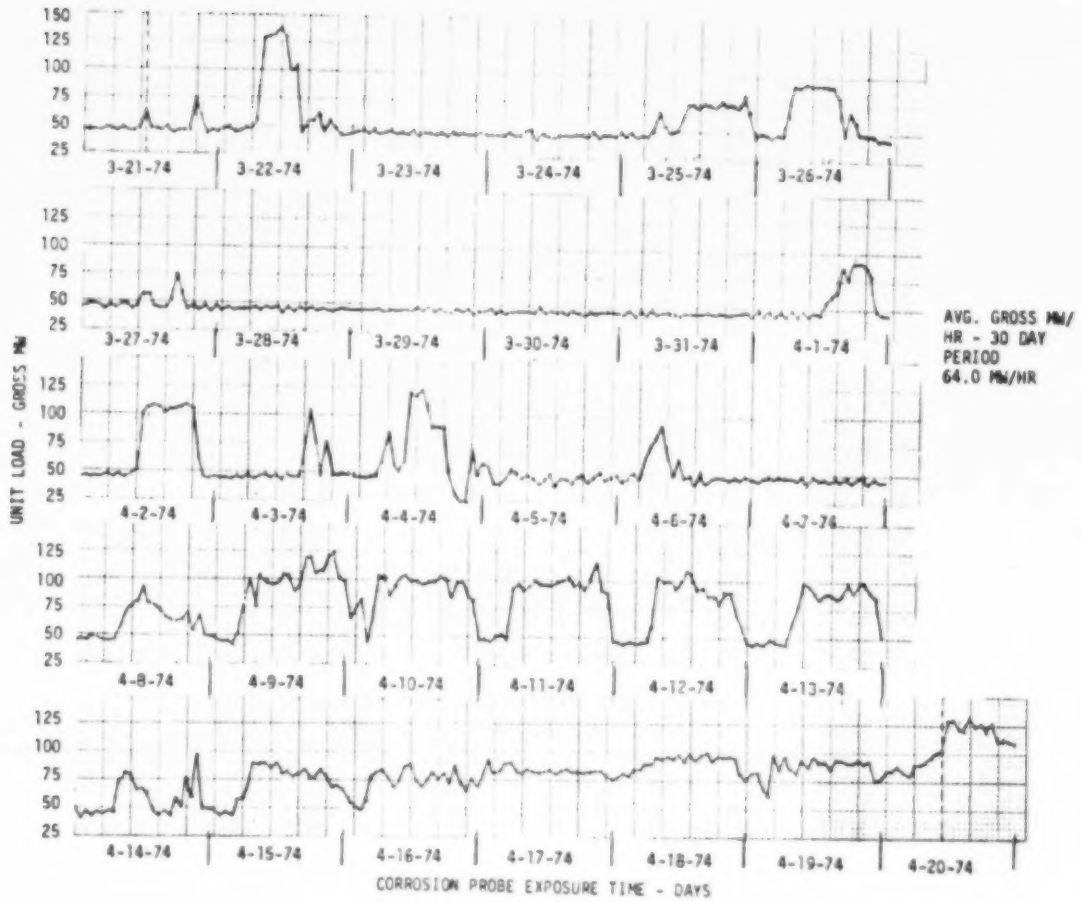


Figure 37: Gross MW Loading Vs. Time - Biased Firing Corrosion Probe Study

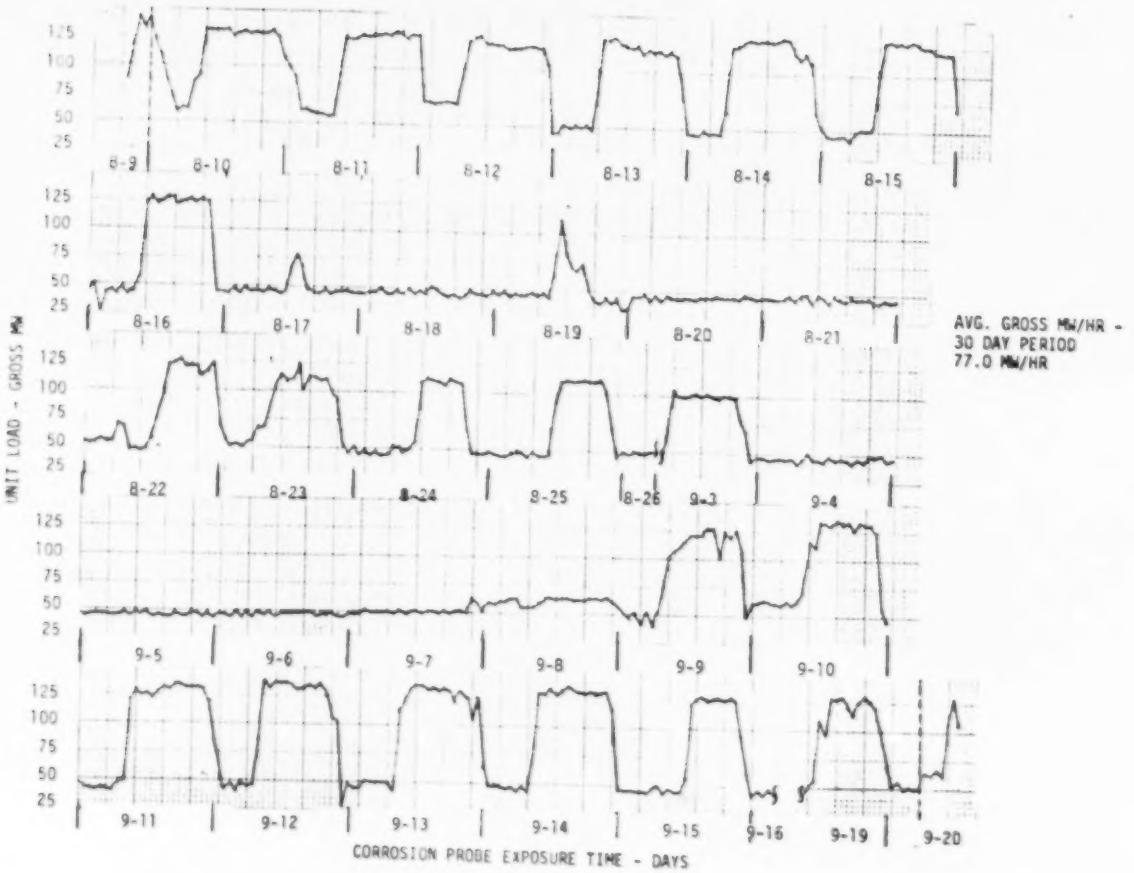


Figure 38: Gross MW Loading Vs. Time - Overfire Air Corrosion Probe Study

Biased Firing Operation

Coal	Auxiliary
	0
0	
	0
0	
	100 Combustion
	100 Air Only
30	
	50
30	

Overfire Air Operation

OFA Dampers 100
100

Coal	Auxiliary
	100
100	
	50
30	
	50
	0
0	
	0
0	
	0

From 204,000 to 272,000 kg/hr steam flow, with three elevations of mills in service, the damper positions were as follows:

Biased Firing Operation

Coal	Auxiliary
	100 Combustion
100	Air Only
	50
20	
	50
	50
20	
	50
20	
	50

Overfire Air Operation

OFA Dampers 100
100

Coal	Auxiliary
	100
100	
	50
30	
	50
	50
30	
	50
0	
	0

At unit loadings above 272,000 kg/hr to the maximum steam flow with the maximum elevations of mills in service, the following damper positions were maintained.*

Biased Firing Operation		Overfire Air Operation	
		OFA Dampers	100
			100
Coal	Auxiliary	Coal	Auxiliary
	100 Combustion		100
100	Air Only	100	
	50		50
30		30	
	50		50
	50		50
30		30	
	50		50
30		30	
	50		50

The percent oxygen was monitored daily during each thirty day study at each probe location and was found to be essentially the same for the various test conditions ranging between 16 and 19 percent O_2.

The weight losses calculated for the biased and overfire air portion of the test program were found to be greater than those for the baseline tests. The average weight losses for all five probes were as follows:

---

* At no time during the biased firing study was the top elevation coal pulverizer placed in service. Maximum unit loading was therefore limited to the maximum with the lower three mills in service.

Baseline	Biased Firing	Overfire Air
2.6381 mg/cm^2	4.6429 mg/cm^2	4.4419 mg/cm^2

These values are within the range of losses which would be expected for oxidation of carbon steel for a 30 day period. To verify this premise control studies were conducted in C-E's Kreisinger Development Laboratory using probes exposed during the biased firing study. These probes were cleaned and prepared in an identical manner to those used for furnace exposure and placed in a muffle furnace for 30 and 60 day exposures at 750 F with a fresh air exchange. The test results were as follows:

Probe	Wt. Loss mg/cm^2 - 30 Days
M (30 day)	4.7999
Q (30 day)	4.7741
R (60 day)	5.1571/2 = 2.5785
B (60 day)	8.3493/2 = 4.1746

These results indicate that the test coupons oxidized more rapidly during the first 30 days exposure with average weight losses decreasing in the second thirty days. Based on these results, it appears that the differences in weight losses observed during the test program are within the ranges to be expected from oxidation alone.

Chemical analysis of deposits taken during the test program does not, in itself, show that molten phase attack has occurred. The composition of the deposits does show some differences, primarily in the iron content as noted on Figure 39. The deposit collected during the biased firing and overfire air tests show 50 and 35 percent iron, respectively, versus 30 percent in the baseline test. Higher iron is normally indicative of lower melting temperatures. However a certain quantity of CaO is necessary to flux the iron if it is to result in a low melting mixture. The CaO content is considerably less in the biased firing and overfire air tests as compared to that of the baseline test. According-

	Waterwall Slag Sample Baseline Test	Coal Ash (As-Fired)	Waterwall Slag Sample Biased Firing Test	Waterwall Slag Sample Overfire Air Test
Ash Fusibility				
IT	1930	2150	2060	1930
ST	2090	2410	2170	2090
HT	2200	2500	+2700	2250
FT	2500	2620	+2700	----
Ash Composition				
SiO_2	46.2	45.8	38.4	38.5
Al_2O_3	18.4	30.7	10.3	18.1
Fe_2O_3	29.9	13.9	50.0	35.4
CaO	3.9	1.8	1.0	1.8
MgO	0.8	1.3	0.3	0.9
Na_2O	0.32	0.4	0.1	0.4
K_2O	0.61	1.4	0.7	1.9
TiO_2	N.R.	0.8	N.R.	1.0
P_2O_5	N.R.	0.5	N.R.	N.R.
SO_3	0.34	1.2	0.8	0.4
	100.4	97.8	101.5	98.4

Figure 39. Ash Analysis

ly the fusibility temperatures are higher for the biased firing test and slightly higher for the overfire air tests. This agrees with observations made during the tests, i.e., deposits during biased firing were more friable and easily removed than in the baseline tests with the overfire air tests falling closer to baseline operation.

For comparison fusibilities and compositions have been given in Figure 39 for the coal ash as fired. This points out the selective deposition of certain constituents in the coal ash, like iron, and also shows that resultant fusibility temperatures of deposits can be significantly different than the coal ash as fired.

Overfire Air Evaluation - Alternate Coal Types

The evaluation of alternate coal types with respect to their effect on unit performance and NO_x emissions optimization was originally proposed as part of this study. However, due to coal supply problems encountered after the start of work, these evaluations proved to be not feasible and were therefore not performed. Tests of a similar nature evaluating Alabama and Midwestern coals were performed during 1973 by Esso Research and Engineering Co. under EPA Contract 68-02-0227 at the Alabama Power Co., Barry No. 4 unit. A discussion of those test results has therefore been included in this report.(2)

Unit Description

Barry No. 4 is a controlled circulation, radiant, reheat, single cell pressurized design firing coal through five elevations of tilting tangential fuel nozzles. Maximum continuous rating is 1,164,969 kg/hr superheat steam flow at 538°C/176 kg/cm^2 and 1,024,566 kg/hr reheat steam flow at 538°C/44 kg/cm^2. Control load rating is 582,485 kg/hr main steam flow.

Alabama and Midwest coals plus petroleum coke were fuels being burned at the time of the test program. The petroleum coke was fired exclu-

sively through the center fuel nozzle (Elevation C) and normally represented one-quarter to one-fifth of the heat input.

Test Objectives

The objectives of the Esso test program were as follows:

1. A series of short (thirty minutes) tests for optimizing NO_x reduction by varying the following:
   A. Excess Air
   B. Nozzle Tilt
   C. Overfire Air
   D. Primary/Auxiliary Air Damper Settings
   E. Unit Load
   F. Pulverizer Coal Fineness
   G. Firing Alabama Coal, Alabama + Coke and Midwest + Coke

2. A two or three day sustained operation at optimum NO_x reduction operating conditions for checking possible short term unit operating problems.

3. A three hundred hour operating period at optimum NO_x reduction conditions for determining possible long term operating problems.

Discussion

Test Data Acquisition

Esso Research measured all gas emission levels with instrumentation located in a specially designed mobile van. The van was located at ground level and had the following instrumentation:

NO	Thermo Electric Chemiluminescence
NO_2	Beckman Ultraviolet, Thermo Electric Chemiluminescence

CO_2, SO_2, CO — Beckman Infrared

O_2 Beckman Paramagnetic

Esso also employed a remote recorder readout of CO, NO_2 and O_2 in the control room for convenience in observing emission levels during testing.

There were no conveniently located test inserts available for gas sampling at the gas duct entering the air heater. Esso, therefore, had to set up a twelve point sampling grid after the air heater. The flue gas sampling rate from each point was proportioned to a gas flow previously determined by velocity traverse. All gas sample lines were heated until the particulate filters, then all condensables are removed by a 32°F ice bath. The gas sample is then blended to one sample per probe location and pumped under 5 pounds pressure to the sample analytical van.

C-E instrumented Corners #1 and 2 windbox compartments to determine the amount of overfire air and the air flow to each compartment. A static pressure tap was installed in each compartment and the pressure differential to the furnace measured.

Petroleum coke, Alabama coal and Midwest coal are normally available at this plant. Normally the coals are fired as mixed in the coal pile. For the test series Alabama and Midwest coals were supplied directly to the bunker. The petroleum coke is burned in a separate Nozzle "C" with coal firing in surrounding Coal Nozzle B and D to insure stable ignition.

Normal coal fineness as taken before the tests was 72 percent thru the 200 mesh screen. Coal fineness was changed to approximately 60 percent thru the 200 mesh screen on several tests to investigate the possible effect on NO_x emission levels.

Esso Research obtained pulverizer coal and coke samples from the feeder belts of each mill on every test. Typical analysis for the coals and coke is presented on Sheet 17.

Unit Performance

Boiler operation as reported on Sheet 15 and 15A was based on board instrumentation. The NO_x, CO, CO_2 and SO_2 PPM values represent data as averaged from Esso data sheets using the appropriate instrument calibration tables.

Test Emission Data

Overfire Air

The greatest effect on NO_x emission levels was obtained by use of overfire air which decreases the amount of air to the firing zone. Figure 40 presents the NO_x emission levels versus percent excess air to the firing zone for all tests. Emission levels are reduced from 525 PPM to approximately 327 PPM in reducing theoretical air from 134 to approximately 95 percent at 0° tilt.

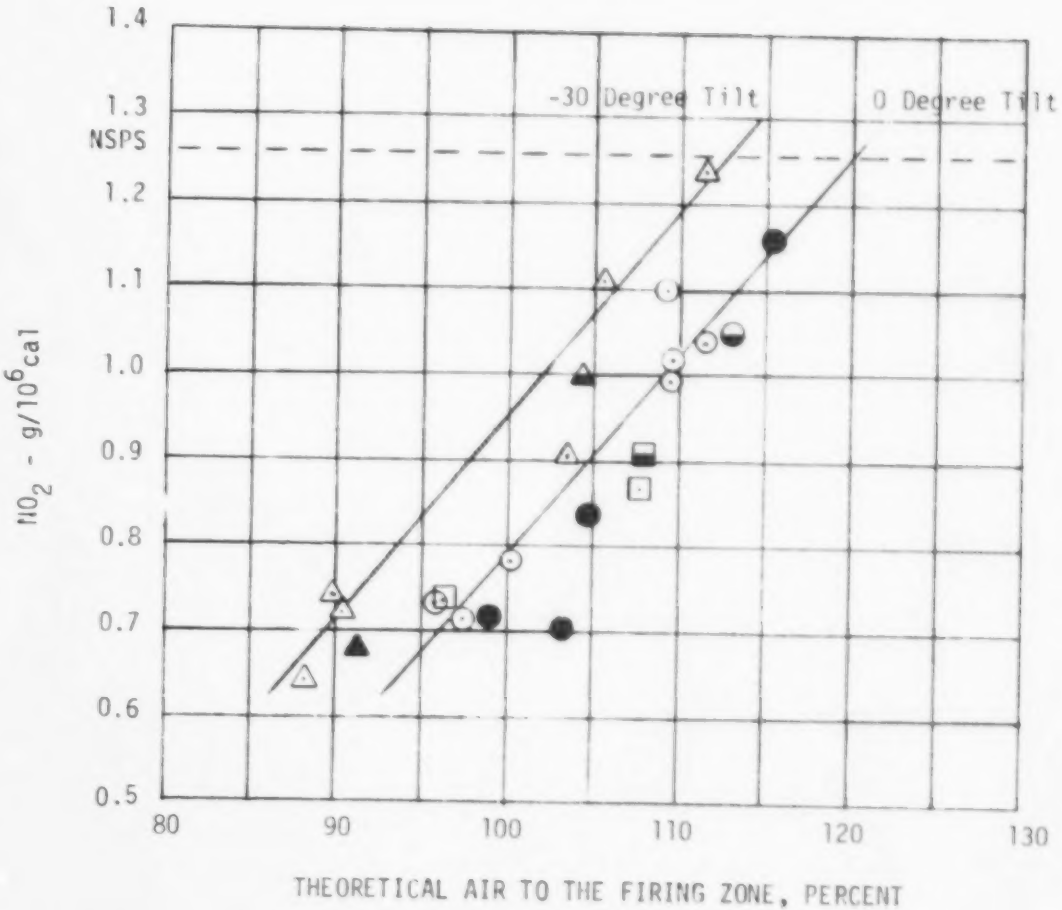
Excess Air

Unit operating excess air as determined at the air heater inlet had no significant effect on NO_x emission levels (corrected to 0 percent excess air when maintaining a constant theoretical air to the firing zone. Figure 41 shows that with this type of operation the unit operating excess air level could be varied from 6 percent to 26 percent with essentially constant NO_x emission; unit excess air was important, however, in keeping CO emissions at low values (Figure 42).

CO Emissions

Figure 42 indicates that CO emissions are a function of percent excess air at the air heater inlet and also the amount of overfire operation. The test data indicates that at 15 percent excess air unit operation and no overfire air the CO emission was 33 PPM which increased to 93 PPM

Alabama Power Company
Barry #4



LEGEND	
Degrees Tilt	Symbol
-20 to -30	△
0	○
+15 to +20	□

SYMBOL	COAL
Open	Alabama + C
Solid	Midwest + C
1/2 Solid	Alabama

Figure 40: NO_2 Vs. Percent Theoretical Air to Firing Zone, All Tests at Unit Loads of 290 to 360 MW

Alabama Power Company
Barry #4

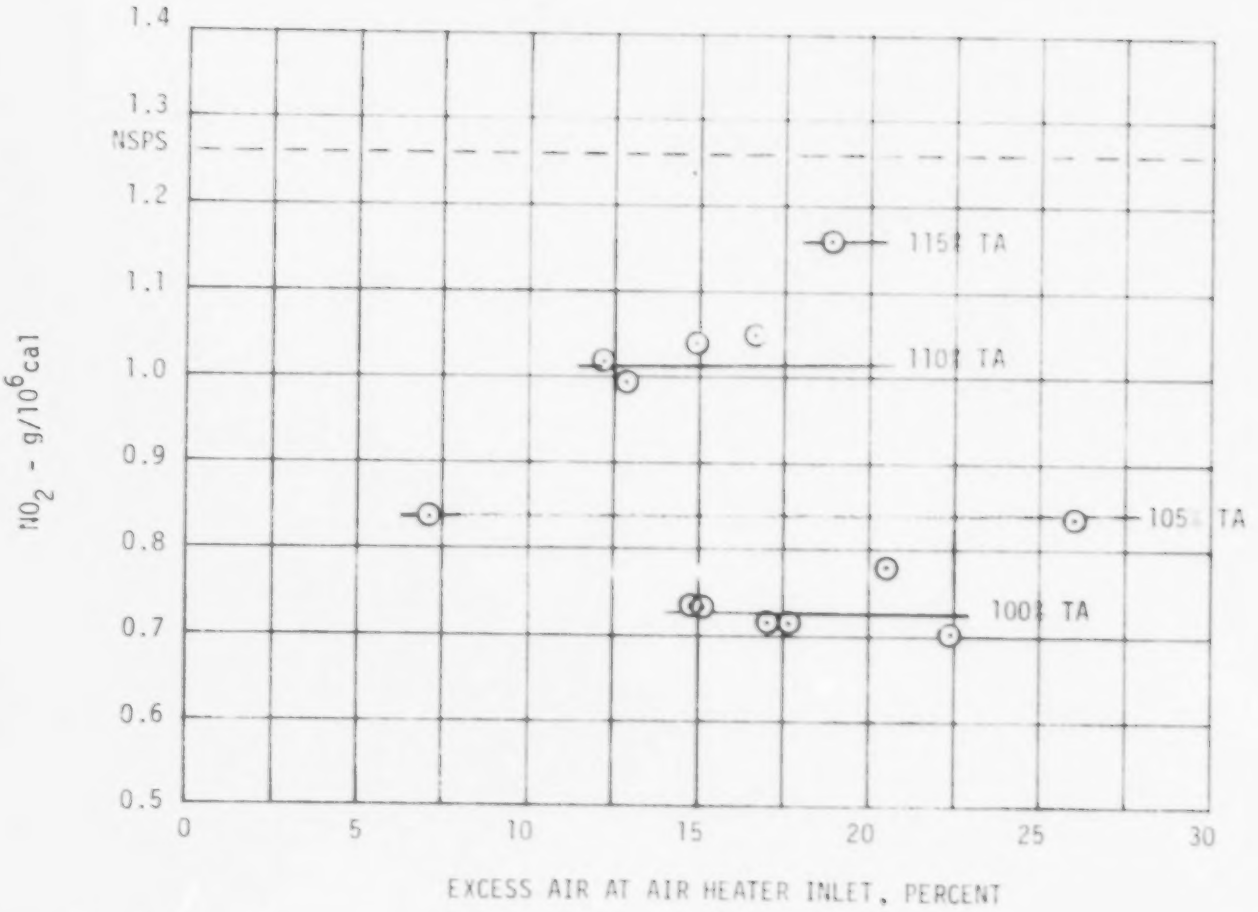
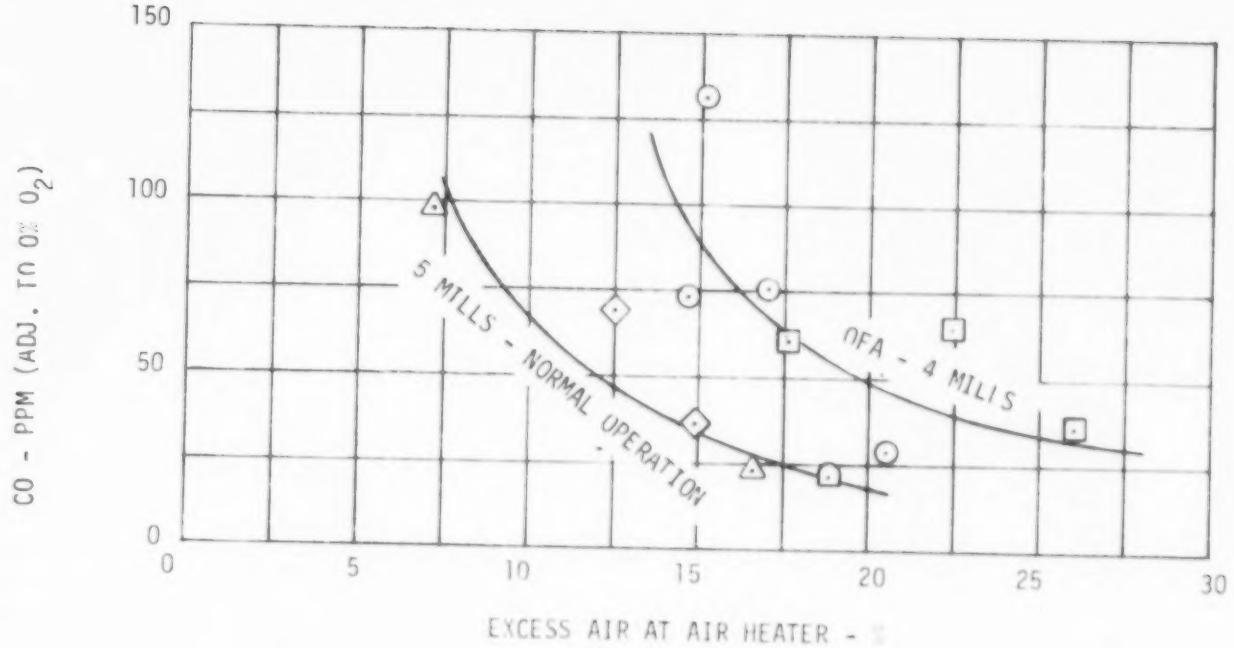


Figure 41: NO_2 Vs. Percent Excess Air at Air Heater Inlet
All Tests at Horizontal Tilt, Unit Load 290 to 360 MW

Alabama Power Company
Barry #4



LEGEND

Symbol	Coal	Mills	Tilt	Operation
△	Ala.	All 5	0	Normal
○	Ala. + C	Lwr. 4	0	OFA
□	MW + C	Lwr. 4	0	OFA
◇	Ala. + C	All 5	0	Normal
⬠	MW + C	All 5	0	Normal

Figure 42: CO Vs. Excess Air, Normal and Overfire Air Operation

with overfire air (90 to 100 percent theoretical air to burner zone). In coal firing 15 percent excess air would seem to be the lowest practicable limit of operation.

Nozzle Tilt

Operating at -30° fuel nozzle tilt increased the NO_x emission approximately 87 PPM over that obtained at 0° tilt. The limited testing with plus tilts of +15° and +20° produced no effect on the measured NO_x emission levels.

Effects of Other Operating Variables

The variation of primary/secondary air dampers (Figure 43) unit load and the pulverized coal fineness had minor effects on NO_x emission levels. This substantiates previous test results and indicates that these operating variables should continue to be used to control normal boiler operation and should not be considered as NO_x controls with coal firing.

Type of Coal

During the test series the following combinations of fuel were fired:

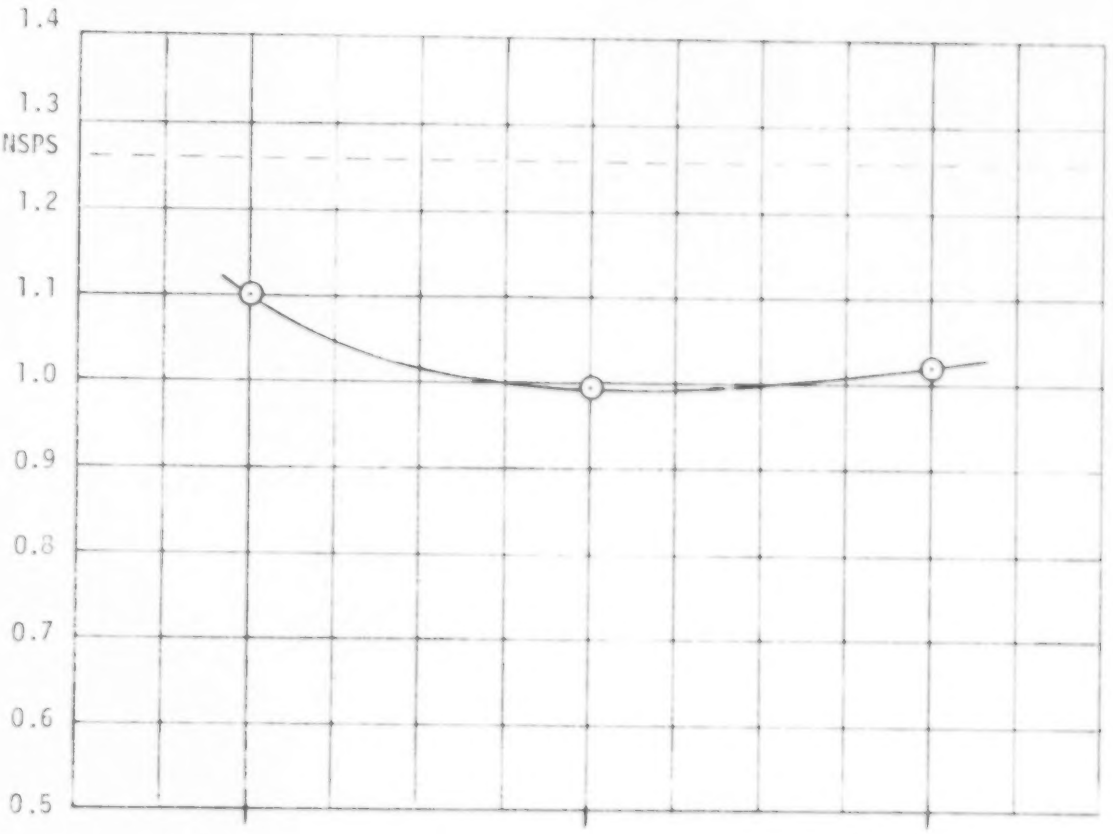
Fuel	No. of Tests
1. Alabama Coal	4
2 Alabama Coal + Coke	15
3. Midwest Coal + Coke	5

Figure 40 plots all tests and identifies the firing combinations and indicates no change in emission levels with fuel change.

Unit Operation

Superheat-reheat outlet temperature of 538/538°C could be maintained at 90 percent MCR horizontal tilt and 95 percent theoretical air to the burner zone which was the optimum NO_x reduction conditions. The overfire

Alabama Power Company
Barry #4



AUX./PRIM. DAMP. - % OPEN	100/20	100/50	50/100
TEST NO.	37	2	35
LOAD - MW	348	348	360
O_2 - %	2.4	2.4	2.4
TILT - DEG.	0	0	0
% THEORETICAL AIR TO FIRING ZONE	109.1	109.4	109.5

Figure 43: Auxiliary/Primary Damper Positions Vs. NO_2

operation maintains the gas weight thru the unit which results in unchanged superheat-reheat performance.

No adverse furnace slagging was noted during the short term tests with low theoretical air to the firing zone. The three hundred hour, long term test with approximately 95 percent theoretical air to the firing zone and 15 percent excess air at air heater inlet was also completed without excessive furnace slag buildup.

300 Hour Corrosion Probe Test Results

Corrosion probes were installed in the furnace of the test boiler by inserting them through available viewpoints in the furnace firing zone as shown on Figure 44. Prior to installing the probes in the test furnace, the probes were prepared by mild acid pickling, preweighing the coupons, and screwing them onto the probes along with the necessary thermocouples. Each probe was then exposed to the furnace atmosphere prevailing for the particular type of operation desired for approximately 300 hours at coupon temperatures of about 468°C in order to accelerate corrosion. After exposure, furnace slag was cleaned off and saved for future analyses, and the coupons were carefully removed from the probes. In the laboratory the coupons were cleaned ultrasonically with fine glass beads to the base metal, and reweighed to determine the weight loss.

Total weight loss data was converted to corrosion rates on a mils per year basis, using the combined inner and outer coupon rates, coupon material density, and exposure time.

Corrosion rates have been determined for 8 coupons installed on 4 probes (2 coupons/probe), in four different locations on the furnace wall. The corrosion data obtained is tabulated on Sheet 16.

Although there is some scatter in the data obtained, Esso concluded "that

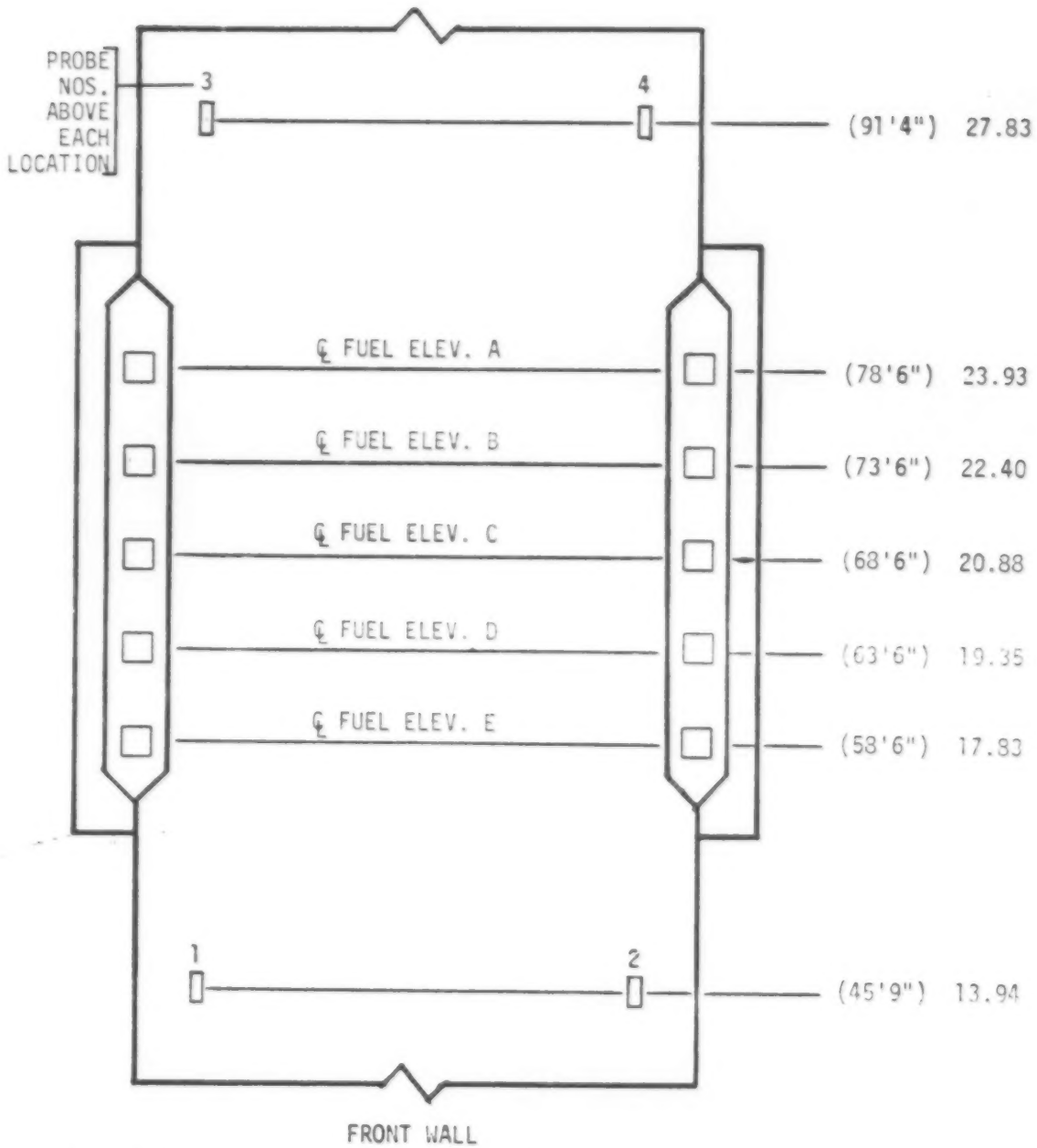


Figure 44: Waterwall Corrosion Probe Locations, Barry No. 4

no major differences in corrosion rates have been observed for coupons exposed to 'low NO_x' conditions compared to those subjected to normal operation."

Esso further concluded that "since corrosion rates were deliberately accelerated in this study in order to develop 'measurable' corrosion rates in a short time period, measured rates, as expected, are much higher than the normal wastage of actual furnace wall tubes."

Task IX - Application Guidelines

The program outlining the application of the technology developed under this study to existing and new tangentially coal fired utility boilers will be presented in the Task IX report and is therefore not discussed as part of this report.

BASELINE STUDY

NO_x TEST DATA SUMMARY

TEST NO.		1	2	3	4	5	6	7
CONDITIONS OF TEST		EXCESS AIR VAR. - CLEAN FURN. COND.						
		1/3 LOAD			1/2 LOAD		FULL LOAD	
DATE		11-16-73	11-16-73	11-16-73	11-16-73	11-16-73	11-16-73	11-16-73
LOAD	MW	98	98	98	98	194	197	193
MAIN STEAM FLOW	10³ KG/HR	314	304	314	316	478	487	479
% EXCESS AIR TOTAL OUTLET	%	20.0	17.5	15.0	15.0	20.7	11.7	10.8
TOTAL AIR TO FUEL FIRING ZONE	%	105.0	117.1	101.3	105.1	117.3	107.3	106.7
MILLS IN SERV.		ABF	ABF	ABF	ABF	ALL	ALL	ALL
OVERFIRE TILT	DEG.	+5	+5	+5	+5	+5	0	0
	Aux.	100	100	100	100	100	100	100
	Fuel	30	30	30	30	30	30	30
	Aux.	100	100	100	100	100	100	100
	Fuel	30	30	30	30	30	30	30
	Aux./Aux.	100/100	100/100	100/100	100/100	100/100	100/100	100/100
	Fuel	30	30	30	30	30	30	30
	Aux.	100	100	100	100	100	100	100
	Fuel	30	30	30	30	30	30	30
	Aux.	100	100	100	100	100	100	100
FURN. TEMPERATURE	°C	580	586	588	588	599	646	638
FURN. TEMPERATURE	°F	1076	1087	1090	1090	1110	1194	1180
FURN. EXIT O2	%	3.1	3.0	2.5	2.5	3.3	2.1	2.0
AIR HEATER EXIT, A.H.	°C	160	160	151	159	194	197	192
	°F	320	320	304	318	381	387	378
	KG/HR	1,010	1,000	1,010	1,000	1,740	761	1,401
	LB/HR	2,230	2,210	2,230	2,210	3,840	1,674	3,090
	KG/HR	4,770	4,756	4,661	4,761	8,670	4,054	4,378
	LB/HR	10,515	10,484	10,280	10,500	19,116	10,886	20,341
	KG/HR	.0076	.180	.0156	.0161	.0287	.198	.0401
	LB/HR	.168	.397	.344	.355	.633	5.0	8.7
	% A.H. IN	.03	.07	.06	.06	.11	2.86	5.79
	% A.H. OUT	.024	.061	.050	.053	.094	4.81	6.87
SMOKE LEVEL IN FLUE GAS	%	.05	.07	.06	.06	.08	.07	.20
FUEL FIRING	BOTTOM					4.77		

TEST NO.		8	9	10	11	12	13	14
CONDITIONS OF TEST		02 - GAS MASS FLOW CORR.				02 - GAS FLOW CORR.		
		FULL LOAD			1/2 LOAD		FULL LOAD	
DATE		11-16-73	11-16-73	11-16-73	11-16-73	11-16-73	11-16-73	11-16-73
LOAD	MW	193	193	193	98	98	197	193
MAIN STEAM FLOW	10³ KG/HR	479	479	479	316	316	487	479
% EXCESS AIR TOTAL OUTLET	%	10.8	10.8	10.8	15.0	15.0	11.7	10.8
TOTAL AIR TO FUEL FIRING ZONE	%	106.7	106.7	106.7	105.1	105.1	107.3	106.7
MILLS IN SERV.		ALL	ALL	ALL	ABF	ABF	ALL	ALL
OVERFIRE TILT	DEG.	0	0	0	+5	+5	-5	-5
	Aux.	100	100	100	100	100	100	100
	Fuel	30	30	30	30	30	30	30
	Aux.	100	100	100	100	100	100	100
	Fuel	30	30	30	30	30	30	30
	Aux./Aux.	100/100	100/100	100/100	100/100	100/100	100/100	100/100
	Fuel	30	30	30	30	30	30	30
	Aux.	100	100	100	100	100	100	100
	Fuel	30	30	30	30	30	30	30
	Aux.	100	100	100	100	100	100	100
FURN. TEMPERATURE	°C	638	638	638	588	588	646	638
FURN. TEMPERATURE	°F	1180	1180	1180	1090	1090	1194	1180
FURN. EXIT O2	%	2.0	2.0	2.0	2.5	2.5	2.1	2.0
AIR HEATER EXIT, A.H.	°C	192	192	192	159	159	197	192
	°F	378	378	378	318	318	387	378
	KG/HR	1,401	1,401	1,401	1,000	1,000	761	1,401
	LB/HR	3,090	3,090	3,090	2,210	2,210	1,674	3,090
	KG/HR	4,378	4,378	4,378	4,761	4,761	4,054	4,378
	LB/HR	20,341	20,341	20,341	10,500	10,500	10,886	20,341
	KG/HR	.0401	.0401	.0401	.0161	.0161	.198	.0401
	LB/HR	8.7	8.7	8.7	35.5	35.5	5.0	8.7
	% A.H. IN	5.79	5.79	5.79	2.41	2.41	2.86	5.79
	% A.H. OUT	6.87	6.87	6.87	5.34	5.34	4.81	6.87
SMOKE LEVEL IN FLUE GAS	%	.20	.20	.20	.06	.06	.07	.20
FUEL FIRING	BOTTOM							

BIASED FIRING STUDY

NO_x TEST DATA SUMMARY

Test No.		15	16	17	18	19
Purpose of Test		Biased Firing - 1 Fuel Elev. Out of Service - Air Dampers Open				
		1/2 Load	3/4 Load	← Max Load →		
Date		1-19-74	1-18-74	12-3-73	12-4-73	12-5-73
Load	MW	66	96	100	103	99
Main Steam Flow	10^3Kg/HR	199	297	315	321	321
Excess Air Econ. Outlet	%	50.1	26.7	21.1	22.2	21.8
Theo. Air to Fuel Firing Zone	%	105.8	121.7	116.5	117.5	117.2
Fuel Elev. In Serv.		ABC	ABC	ABC	ABD	ACD
Fuel Nozzle Tilt	Deg.	-9	0	-15	-15	-10
Aux.		50	50	50	50	50
A Fuel		20	20	30	30	30
Aux.		50	50	50	50	100
B Fuel		20	20	30	30	100
Aux./Aux.		50/50	50/50	50/50	50/100	50/50
C Fuel		20	20	30	100	30
Aux.		50	50	50	50	50
D Fuel		100	100	100	30	30
Aux.		100	100	100	50	50
SHO Temperature	°C	546	539	529	543	523
RHO Temperature	°C	496	506	501	520	486
Unit Efficiency	%	87.9	89.3	89.1	89.3	88.9
Gas Weight Ent. A.H.	10^3Kg/HR	341	430	439	455	428
NO	PPM - 6% O_2	594	543	397	373	387
NO_x	GR/10^6CAL	1.206	1.142	.840	.792	.795
SO_2	PPM - 3% O_2	1721	1682	2422	2553	2292
SO_2	GR/10^6CAL	4.861	4.922	7.137	7.536	6.543
CO	PPM - 6% O_2	33.38	29.10	45.63	38.51	35.48
CO	GR/10^6CAL	.0412	.0372	.0588	.0497	.0443
HC	PPM - % O_2	0.0	0.0	0.0	.012	.012
O_2	% A.H. In	7.10	4.55	3.72	3.885	3.825
O_2	% A.H. Out	8.54	7.19	6.08	5.80	6.30
Carbon Loss in Flyash	%	.32	.34	.46	.37	.42

Test No.		20	21	22	23	24
Purpose of Test		Biased Firing - 1 Fuel Elev. Out of Service - Air Dampers Open				
		Max Load	3/4 Load	← 1/2 Load →		
Date		12-6-73	1-18-74	1-19-74	1-19-74	1-19-74
Load	MW	102	94	64	64	66
Main Steam Flow	10^3Kg/HR	314	308	208	211	202
Excess Air Econ. Outlet	%	24.2	29.0	48.0	47.0	47.0
Theo. Air to Fuel Firing Zone	%	94.7	97.3	112.5	141.4	141.3
Fuel Elev. in Service.		BCD	BCD	BCD	ACD	ABD
Fuel Nozzle Tilt	Deg.	-5	+10	0	0	-15
Aux.		100	100	100	50	50
A Fuel		100	100	100	20	20
Aux.		50	50	50	100	50
B Fuel		30	20	20	100	20
Aux./Aux.		50/50	50/50	50/50	50/50	50/100
C Fuel		30	20	20	20	100
Aux.		50	50	50	50	50
D Fuel		30	20	20	20	20
Aux		50	50	50	50	50
SHO Temperature	°C	544	512	501	507	544
RHO Temperature	°C	515	469	448	454	513
Unit Efficiency	%	88.8	89.6	87.8	87.9	87.7
Gas Weight Ent. A.H.	10^3Kg/HR	451	435	360	361	356
NO	PPM - 6% O_2	285	331	520	485	609
NO_x	GR/10^6CAL	.599	.696	1.124	1.043	1.282
SO_2	PPM - 3% O_2	2277	1566	1861	2245	1807
SO_2	GR/10^6CAL	6.661	4.578	5.593	6.710	5.288
CO	PPM - 6% O_2	26.61	31.28	29.10	22.41	27.54
CO	GR/10^6CAL	.0341	.0400	.0382	.0293	.0353
HC	PPM - % O_2	0.0	0.0	0.0	0.0	0.0
O_2	% A.H. In	4.165	4.76	6.93	6.85	6.79
O_2	% A.H. Out	7.31	8.37	8.40	8.58	6.87
Carbon Loss in Flyash	%	.25	.30	.20	.11	.21
Dust Loading	GR/SCM	8.65				

NO_X TEST DATA SUMMARY
BASELINE STUDY AFTER MODIFICATION

TEST NO.		1	2	3	4	5	6	7
Purpose of Test		Excess Air Var. - Clean Furnace Cond.						
		← 1/2 Load →		← 3/4 Load →		← Maximum Load →		
Date		6/25/74	6/25/74	6/25/74	6/27/74	6/19/74	6/27/74	6/27/74
Load	MW	62	62	64	92	131	127	125
Main Steam Flow	10^3KG/HR	219	213	217	315	450	441	423
Excess Air Econ. Outlet	%	33.5	16.0	64.7	15.5	21.0	12.4	25.4
Theo. Air to Fuel Firing Zone	%	127.1	113.4	155.4	111.0	115.3	107.1	119.5
Fuel Elev. In Serv.		ABC	ABC	ABC	ABC	ALL	ALL	ALL
OFA Nozzle Tilt	DEG.	0	0	0	0	0	0	0
Fuel Nozzle Tilt	DEG.	3	6	-14	2	-13	-3	-22
OFA		-	0	0	0	0	0	0
OFA		0	0	0	0	0	0	0
Aux.		20	0	50	30	80	100	100
Fuel		30	30	30	20	30	30	35
Aux.		20	0	50	60	100	100	100
Fuel		30	30	30	20	30	30	35
Aux./Aux.		20/20	10/10	50/50	80/80	100/100	100/100	100/100
Fuel		30	30	30	20	30	30	35
Aux.		20	10	50	50	100	100	100
Fuel		5	0	0	0	30	30	35
Aux.		0	0	0	0	100	100	100
SHO Temperature	°C	492	468	516	504	529	524	518
RHO Temperature	°C	435	402	493	466	488	487	480
Unit Efficiency	%	88.4	88.8	87.4	89.8	88.4	89.2	89.5
Gas Weight Ent. A.H.	10^3KG/HR	335	270	413	398	593	546	559
NO_x	PPM - 0% O_2	444	335	640	327	404	330	477
NO_2	GR/10^6CAL	.929	.701	1.339	.684	.846	.692	1.000
SO_2	PPM - 0% O_2	1678	1621	2611	2634	2251	2677	2707
SO_2	GR/10^6CAL	10.718	10.551	7.696	7.674	6.559	7.800	7.889
CO	PPM - 0% O_2	27.54	376.77	34.66	109.70	96.37	127.2	21.74
CO	GR/10^6CAL	.0351	.4790	.0442	.1398	.0336	.1622	.0277
HC	PPM - 0% O_2	0	0	0	0	0	0	0
O_2	% A.H. In.	5.36	2.96	8.36	2.87	3.71	2.36	4.34
O_2	% A.H. Out.	7.35	5.52	9.70	5.5	7.36	5.75	7.02
Carbon Loss In Flyash	%	.29	.23	1.06	.11	.75	.51	.74

TEST NO.		8	9	10	11	12	13	14
Purpose of Test		E.A. Var. - Mod. Dirty Furnace			E.A. Var. - Dirty Furnace			
		← Maximum Load →			1/2 Load		Maximum Load	
Date		6/20/74	6/20/74	6/28/74	6/26/74	6/26/74	6/28/74	6/28/74
Load	MW	130	129	125	65	66	126	125
Main Steam Flow	10^3KG/HR	440	446	428	236	218	432	425
Excess Air Econ. Outlet	%	17.8	12.1	28.6	30.9	69.1	22.0	25.9
Theo. Air to Fuel Firing Zone	%	112.3	106.9	120.5	124.9	154.0	116.2	119.9
Fuel Elev. In Serv.		ALL	ALL	ALL	ABC	ABC	ALL	ALL
OFA Nozzle Tilt	DEG.	0	0	0	0	0	0	0
Fuel Nozzle Tilt	DEG.	-21	-17	-6	-16	-16	-6	-6
OFA		0	0	0	0	0	0	0
OFA		0	0	0	0	0	0	0
Aux.		80	80	100	20	50	100	100
Fuel		30	30	30	30	30	30	30
Aux.		100	100	100	20	50	100	100
Fuel		30	30	30	30	30	30	30
Aux./Aux.		100/100	100/100	100/100	20/20	50/50	100/100	100/100
Fuel		30	30	30	30	30	30	30
Aux.		100	100	100	20	50	100	100
Fuel		30	30	30	0	0	30	30
Aux.		100	100	100	0	0	100	100
SHO Temperature	°C	526	528	524	507	531	524	529
RHO Temperature	°C	486	483	480	457	498	496	499
Unit Efficiency	%	89.0	88.9	89.5	89.3	88.0	89.0	89.4
Gas Weight Ent. A.H.	10^3KG/HR	565	542	564	363	419	575	583
NO_x	PPM - 0% O_2	470	334	431	373	626	391	431
NO_2	GR/10^6CAL	.986	.699	.902	.782	1.310	.819	.902
SO_2	PPM - 0% O_2	1941	2482	2500	2558	2461	2564	2629
SO_2	GR/10^6CAL	5.655	7.232	7.283	7.453	7.171	7.470	7.661
CO	PPM - 0% O_2	24.31	97.16	23.55	26.28	23.85	23.4	22.92
CO	GR/10^6CAL	.0310	.1239	.0300	.0335	.0304	.0298	.0292
HC	PPM - 0% O_2	0	0	0	0	0	0	0
O_2	% A.H. In.	3.24	2.31	4.5	5.04	8.23	3.86	4.4
O_2	% A.H. Out.	6.6	6.9	7.48	7.55	10.75	7.3	7.15
Carbon Loss In Flyash	%	.22	.42	.61	.17	.05	.36	.25

NO_X TEST DATA SUMMARY

OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.		15	16	17	18A	19
Purpose of Test		OFA Damper Position Variation				
		← 3/4 Load →				
Date		7/10/74	7/10/74	7/10/74	7/12/74	7/11/74
Load	MW	97	98	100	100	100
Main Steam Flow	10^3KG/HR	336	340	338	344	338
Excess Air Econ. Outlet	%	28.5	27.1	25.6	26.6	24.8
Theo. Air to Fuel Firing Zone	%	114.5	96.7	95.8	84.8	89.3
Fuel Elev. In Serv.		BCD	BCD	BCD	BCD	BCD
OFA Nozzle Tilt	DEG.	0	0	0	0	0
Fuel Nozzle Tilt	DEG.	-5	-5	-5	-4	-4
NOZZLE CONF. / DAMPER POS. & OPEN: OFA		0	100	0	100	50
OFA		0	0	100	100	50
Aux.		0	0	0	0	0
A Fuel		0	0	0	0	0
Aux.		50	50	50	50	50
Fuel		30	30	30	30	30
Aux./Aux.		50/50	50/50	50/50	50/50	50/50
Fuel		30	30	30	30	30
Aux.		50	50	50	50	50
Fuel		30	30	30	30	30
Aux.		50	50	50	50	50
SHO Temperature	°C	518	510	514	524	521
RHO Temperature	°C	457	452	457	476	486
Unit Efficiency	%	90.0	89.8	89.7	89.6	89.3
Gas Weight Ent. A.H.	10^3KG/HR	458	447	442	466	468
NO_x	PPM - 0% O_2	345	254	254	229	232
NO_2	GR/10^6CAL	.723	.533	.533	.479	.486
SO_2	PPM - 0% O_2	1892	1973	2092	2397	2684
SO_2	GR/10^6CAL	5.512	5.750	6.097	6.984	7.821
CO	PPM - 0% O_2	28.10	29.96	32.4	48.08	39.20
CO	GR/10^6CAL	.0358	.0382	.0413	.0613	.0500
HC	PPM - 0% O_2	0	0	0	0	0
O_2	% A.H. In.	4.74	4.55	4.36	4.5	4.25
O_2	% A.H. Out.	6.51	6.49	6.08	6.32	6.05
Carbon Loss In Flyash	%	.51	.59	.63	.54	.32

TEST NO.		20	21	22	23
Purpose of Test		OFA Damper Position Variation			
		← 3/4 Load →			
Date		7/11/74	7/12/74	7/12/74	7/12/74
Load	MW	100	102	102	102
Main Steam Flow	10^3KG/HR	344	342	341	346
Excess Air Econ. Outlet	%	25.4	25.4	27.9	28.1
Theo. Air to Fuel Firing Zone	%	100.5	117.4	90.4	96.9
Fuel Elev. In Serv.		BCD	ABC	ABC	ABC
OFA Nozzle Tilt	DEG.	0	0	0	0
Fuel Nozzle Tilt	DEG.	-4	-4	-4	-4
NOZZLE CONF. / DAMPER POS. & OPEN: OFA		0	0	100	50
OFA		0	0	100	50
Aux.		100	100	100	50
A Fuel		0	100	100	50
Aux.		50	50	50	50
Fuel		30	30	30	30
Aux./Aux.		50/50	50/50	50/50	50/50
Fuel		30	30	30	30
Aux.		50	50	50	50
Fuel		30	0	0	0
Aux.		50	0	0	0
SHO Temperature	°C	524	532	524	521
RHO Temperature	°C	479	498	491	485
Unit Efficiency	%	90.2	90.1	89.0	89.1
Gas Weight Ent. A.H.	10^3KG/HR	468	476	494	492
NO_x	PPM - 0% O_2	323	483	329	336
NO_2	GR/10^6CAL	.677	1.012	.689	.704
SO_2	PPM - 0% O_2	1021	1814	2259	2417
SO_2	GR/10^6CAL	5.308	5.284	6.583	7.042
CO	PPM - 0% O_2	28.79	25.16	25.79	25.28
CO	GR/10^6CAL	.0367	.0321	.0329	.0322
HC	PPM - 0% O_2	0	0	0	0
O_2	% A.H. In.	4.33	4.33	4.67	4.69
O_2	% A.H. Out.	5.14	6.05	6.46	6.72
Carbon Loss In Flyash	%	.49	.46	.54	.60

NO_X TEST DATA SUMMARY

OFA TILT VARIATION

TEST NO.		24	25	26	27	28	29
Purpose of Test		OFA & Fuel Nozzle Tilt Variation					
		← Full Load →					
Date		7/29/74	7/29/74	7/29/74	7/29/74	7/29/74	7/29/74
Load	MW	124	124	124	125	125	124
Main Steam Flow	10^3KG/HR	407	418	412	407	414	418
Excess Air Econ. Outlet	%	25.9	23.7	25.1	22.3	20.2	23.7
Theo. Air to Fuel Firing Zone	%	94.2	92.4	93.2	91.5	89.6	92.6
Fuel Elev. In Serv.		ALL	ALL	ALL	ALL	ALL	ALL
OFA Nozzle Tilt	DEG.	0	0	0	-30	-30	+30
Fuel Nozzle Tilt	DEG.	-5	-23	+19	-5	+22	-21
OFA		100	100	100	100	100	100
OFA		100	100	100	100	100	100
Aux.		100	100	100	100	100	100
Fuel		100	100	100	100	100	100
Aux.		50	50	50	50	50	50
Fuel		30	30	30	30	30	30
Aux./Aux.		50/50	50/50	50/50	50/50	50/50	50/50
Fuel		30	30	30	30	30	30
Aux.		50	50	50	50	50	50
Fuel		30	30	30	30	30	30
Aux.		50	50	50	50	50	50
SHO Temperature	°C	538	521	524	527	524	521
RHO Temperature	°C	532	508	527	533	535	505
Unit Efficiency	%	89.6	89.3	88.9	89.3	88.6	89.4
Gas Weight Ent. A.H.	10^3KG/HR	548	566	585	557	586	544
NO_x	PPM - 0% O_2	339	290	368	344	404	285
NO_2	GR/10^6CAL	.710	.609	.770	.721	.846	.596
SO_2	PPM - 0% O_2	2450	2920	3310	3160	3370	3240
SO_2	GR/10^6CAL	7.140	8.511	9.647	9.208	9.820	9.443
CO	PPM - 0% O_2	25.4	27.1	31.8	22.1	28.2	49.4
CO	GR/10^6CAL	.0324	.0346	.0406	.0282	.0360	.0630
HC	PPM - 0% O_2	0	0	0	0	0	0
O_2	% A.H. In.	4.4	4.1	4.3	3.9	3.6	4.1
O_2	% A.H. Out.	5.9	6.0	6.2	6.0	5.8	6.4
Carbon Loss In Flyash	%	.37	.37	.40	.29	.29	.49

LOAD VARIATION AT OPTIMUM CONDITIONS

TEST NO.		30	31	32	33	34	35
Purpose of Test		Load Variation at Optimum Conditions					
		Max. Load	3/4 Load	1/2 Load	Max. Load	3/4 Load	1/2 Load
Date		7/30/74	7/31/74	7/31/74	7/31/74	7/31/74	8/1/74
Load	MW	125	97	65	122	95	64
Main Steam Flow	10^3KG/HR	416	314	204	409	310	204
Excess Air Econ. Outlet	%	21.6	25.2	46.9	27.4	27.4	45.9
Theo. Air to Fuel Firing Zone	%	90.7	89.4	88.5	94.6	90.6	88.5
Fuel Elev. In Serv.		ALL	ABC	AB	ALL	ABC	AB
OFA Nozzle Tilt	DEG.	0	-12	0	-22	-22	-10
Fuel Nozzle Tilt	DEG.	-4	-16	-5	-22	-22	-15
OFA		100	100	100	100	100	100
OFA		100	100	100	100	100	100
Aux.		100	100	100	100	100	100
Fuel		100	100	100	100	100	100
Aux.		50	50	50	50	50	50
Fuel		30	30	30	30	30	30
Aux./Aux.		50/50	50/50	50/0	50/50	50/50	50/0
Fuel		30	30	0	30	30	0
Aux.		50	50	0	50	50	0
Fuel		30	0	0	30	0	0
Aux.		50	0	0	50	0	0
SHO Temperature	°C	538	525	535	521	506	512
RHO Temperature	°C	536	514	514	521	493	493
Unit Efficiency	%	89.0	89.1	89.2	89.0	88.2	89.0
Gas Weight Ent. A.H.	10^3KG/HR	574	456	341	584	472	329
NO_x	PPM - 0% O_2	339	338	396	333	291	313
NO_2	GR/10^6CAL	.710	.708	.828	.697	.608	.655
SO_2	PPM - 0% O_2	1680	1730	1740	2430	2490	2420
SO_2	GR/10^6CAL	4.896	5.043	5.070	7.083	7.256	6.960
CO	PPM - 0% O_2	26.1	26.1	24.4	24.8	26.4	25.0
CO	GR/10^6CAL	.0333	.0333	.0311	.0316	.0337	.0319
HC	PPM - 0% O_2	0	0	0	0	0	0
O_2	% A.H. In.	3.8	4.3	6.8	4.6	4.6	6.7
O_2	% A.H. Out.	5.3	5.7	8.2	6.3	6.8	8.4
Carbon Loss In Flyash	%	.61	.39	.32	.24	.33	.15
Dust Loading	GR/SCM	8.64					

BASELINE STUDY
TEST DATA

BASELINE STUDY
TEST DATA

BIASED FIRING STUDY
TEST DATA

TEST NO.		15	16	17	18	19	20	21	22	23	24
Date		1/19/74	1/18/74	12/3/73	12/4/73	12/5/73	12/6/73	1/18/74	1/19/74	1/19/74	1/19/74
Time		09:10	18:24	11:07	01:30	23:50	02:30	20:30	15:45	13:30	11:00
Unit Load	MW	66	96	100	103	99	102	94	64	64	66
FLOWS - 10^3KG/HR											
Feedwater		199	296	304	310	314	307	307	203	209	196
SH Spray (Heat Balance)		0	1.77	10.85	11.15	5.54	7.08	1.50	2.18	1.77	7.62
Main Steam		199	297	315	321	321	314	308	208	211	203
Turbine Leakage		9.06	13.4	13.7	13.9	14.2	13.7	13.8	9.5	9.6	9.1
RH Extraction		12.1	20.9	22.0	22.2	23.1	22.7	22.2	13.3	13.6	11.4
RH Spray (Heat Balance)		.091	.272	.408	.272	.091	.408	.045	0.0	0.0	.091
RH Flow (Calc.)		178	264	280	284	282	278	272	185	186	181
AIR & GAS FLOWS - 10^3KG/HR											
Gas Ent. AH		341	430	439	455	428	451	435	360	361	344
Gas Lvg. AH		377	505	502	499	479	511	507	400	403	382
Air Ent. AH		356	475	467	465	446	477	476	376	380	362
Air Lvg. AH		350	398	405	421	396	418	405	337	339	334
AH Leakage		35.5	76.8	62.8	43.1	50.6	59.8	72.8	39.6	42.5	47.9
UNIT ABSORPTION - 10^6KG-CAL/HR											
Economizer		8.88	10.05	10.01	10.045	9.4	9.8	9.55	8.45	8.65	9.13
Furnace		76.4	110	115	116	120.5	116.5	105.8	80.0	80.8	73.9
Drum - DESH		27.2	36.6	39.8	43.1	35.4	39.2	34.8	23.3	24.2	22.1
DESH - SH Out.		11.5	21.0	22.4	22.9	23.9	24.0	19.4	12.1	12.7	14.0
RH		17.5	26.2	28.1	29.4	26.9	28.1	25.2	17.6	17.8	19.4
Tota.		141.5	204	216	222	216	218	205	141.5	144	138.5
PRESSURES											
STEAM & WATER - KG/CM^2											
Economizer In.		138.5	139.9	132.2	132.9	133.6	133.9	139.5	138.7	138.4	138.4
Drum		137.2	138.4	130.7	131.3	132	132.4	138	137.3	137	137
SH - DESH In.		132.8	133.1	129.4	130	130.3	130.8	132.8	133.1	132.5	133.1
SH Out.		130.3	130.2	128.6	129.4	129.4	129.7	129.9	130.2	130.1	130.2
RH In.		14.84	22.26	22.89	23.24	21.98	22.75	22.4	14.98	14.84	14.33
RH Out.		14.0	21.0	21.7	22.05	21.49	21.56	21.14	14.14	14	13.91
AIR & GAS - CM. WG											
FD Fan Out.		2.03	7.87	7.37	7.11	4.06	6.1	7.87	2.29	2.03	2.032
"B" AH Air Out.		-.508	2.03	2.03	2.03	.762	1.27	2.29	-.254	-.254	.508
"B" AH Gas Out.		-14.73	-18.8	-18.8	-19.81	-17.78	-18.8	-18.8	-14.22	-14.22	-14.22
"D" Elev. Left Rear Fuel Air Comp.		-.762	1.27	1.27	-1.52	-1.52	-1.78	-.508	-2.03	-2.03	-2.03
"A" Elev. Left Rear Fuel Air Comp.		-1.27	-.762	1.02	-1.02	-1.78	.254	.76	-.76	-2.03	-2.03
Left Mill Duct at Windbox		-.762	1.016	1.27	1.016	-.508	.508	1.27	-.762	-1.016	-1.016
Mill Air Duct at "B" Elev. Mill		-2.29	-.762	-.508	-1.016	-1.27	-2.03	-.254	-2.29	-1.52	-2.29
Upper Furnace		-2.03	-1.78	-2.03	-2.03	-2.03	-2.03	-1.78	-1.78	-2.03	-1.78
TEMPERATURES - °C											
STEAM & WATER											
SH Out.		546	539	529	543	523	544	512	501	507	544
SH DESH In.		459	456	454	466	429	449	427	427	431	472
SH DESH Out.		452	435	425	43[illegible]	41[illegible]	431	423	420	424	430

BIASED FIRING STUDY
TEST DATA

TEST NO.	15	16	17	18	19	20	21	22	23	24
TEMPERATURES - °C										
STEAM & WATER (Cont.)										
RH Out.	496	506	501	520	486	515	469	448	454	513
RH DESH In.	307	320	315	327	308	327	297	268	274	307
RH DESH Out.	307	319	313	326	308	326	297	268	274	307
Economizer In.	200	218	218	219	217	217	217	199	199	200
Economizer Out.	241	450	248	450	244	247	245	237	237	243
#5 HP Heater In.	169	185	184	185	182	183	183	169	169	169
#5 HP Heater Out.	200	219	219	220	218	218	217	200	201	201
#5 HP Heater Ext. In.	297	313	308	321	302	321	291	261	266	297
#5 HP Heater Drain	197	214	215	216	213	213	214	197	197	196
Spray Water	135	149	149	150	147	147	148	136	136	136
AIR & GAS										
AH Gas In.	298	311	307	311	301	305	312	293	293	298
AH Gas Out.	154	147	145	147	140	136	143	147	146	150
AH Air In.	28.3	44.4	38.4	37.8	23.3	17.2	44.0	37.2	32.2	30.0
AH Air Out.	273	271	271	274	268	269	265	268	268	268
Furnace Outlet (Avg.)	1036	1197	1246	1253	1171	1195	1129	999	873	827
Air Heater Leakage %	10.4	17.89	14.32	9.46	11.8	13.24	16.73	11.02	11.77	13.46
AH Gas Side Efficiency %	51.1	55.4	55.3	56.8	53.4	53.8	56.3	52.7	51.8	49.9
Unit Efficiency %	87.9	89.3	89.1	89.3	89.0	88.8	89.6	87.8	87.9	87.8
PRODUCTS OF COMBUSTION - GR/10^6CAL.										
AH INLET										
Dry Air	1962	1720	1650	1670	1610	1685	1745	2060	2036	1990
Wet Air	2000	1740	1670	1690	1632	1705	1770	2084	2060	2016
Dry Prod.	2010	1780	1715	1732	1670	1745	1810	2130	2100	2060
Wet Prod.	2120	1875	1815	1830	1765	1840	1900	2230	2205	2150
AH OUTLET										
Dry Air	2100	2050	1910	1841	1816	1925	2060	2300	2295	2280
Wet Air	2210	2080	1935	1865	1840	1950	2090	2330	2320	2310
Dry Prod.	2240	2115	1970	1905	1880	1990	2125	2370	2355	2345
Wet Prod.	2340	2210	2080	2010	1970	2085	2190	2480	2460	2445
EXCESS AIR - %										
AH In.	50.1	26.7	21.1	22.2	21.8	24.2	29.0	48.0	47.0	47.0
AH Out.	66.7	51.1	39.9	34.7	37.3	42.0	52.2	65.4	65.5	68.1
FUEL ANALYSIS - %										
Carbon	63.5	64.8	64.3	64.7	62.5	64.8	65.2	63.1	65.5	65.4
Hydrogen	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.1	4.1	4.1
Nitrogen	1.1	1.2	1.1	1.1	1.1	1.1	1.2	1.1	1.1	1.1
Oxygen	6.4	5.5	5.9	5.9	5.9	5.9	5.5	6.4	6.4	6.4
Sulfur	2.3	2.2	2.9	2.8	2.7	2.5	2.1	2.4	2.6	2.2
Moisture	9.7	10.4	11.6	11.4	10.0	9.4	9.0	11.9	12.2	9.2
Ash	12.9	11.8	10.0	9.9	13.6	12.1	12.9	11.0	10.1	11.6
HHV - CAL/G	6510	6416	6360	6383	6399	6438	6455	6088	6332	6444

TEST DATA
BASELINE STUDY AFTER MODIFICATION

TEST DATA
BASELINE STUDY AFTER MODIFICATION

TEST DATA
OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.	15	16	17	18	19	20	21	22	23
Date	7/10/74	7/10/74	7/10/74	7/12/74	7/11/74	7/11/74	7/12/74	7/12/74	7/12/74
Time	0:00	2:15	4:00	7:25	4:35	23:10	1:24	3:30	4:45
Unit Load - MW	97	98	100	100	100	100	102	102	102
FLOWS - 10^3KG/HR									
Feedwater	336	340	338	343	325	337	330	326	330
SH Spray (Heat Balance)	.046	.682	.409	.909	13	6.95	11.5	15.55	15.45
Main Steam	336	340	338	344	338	344	342	341	346
Turbine Leakage	15.18	15.31	15.22	15.5	15.23	15.5	15.4	15.4	15.59
RH Extract	27.18	27.41	27.55	28.09	26.14	25.18	24.86	24.36	25.59
RH Spray (Heat Balance)	.682	2.409	3.273	.682	1.14	.136	0	0	0
RH Flow (Calc.)	295	300	299	301	298	304	301	302	305
RH Flow (Test)	299	300	303	300	295	298	297	299	299
AIR & GAS FLOWS - 10^3KG/HR									
Gas Ent. AH	458	447	442	466	468	468	476	494	492
Gas Lvg. AH	509	501	489	519	519	521	526	550	556
Air Ent AH	477	470	457	486	484	488	493	515	521
Air Lvg. AH	426	415	410	433	433	436	443	460	457
AH Leakage	51.2	54.7	46.5	52.8	52.8	52.2	50.1	55.7	64.0
UNIT ABSORPTION - 10^6KG-CAL/HR									
Economizer	9.88	7.23	6.15	10.31	10.16	10.33	10.53	10.61	10.74
Furnace	127.89	131.64	131.9	129.78	122.93	122.99	124.49	122.75	124.41
Drum - DESH	34.62	34.37	34.78	36.87	38.86	37.27	39.56	40.24	40.17
DESH - SH Out.	20.92	21.24	21.39	22.81	24.97	24.95	26.06	25.60	25.58
RH	25.93	27.44	26.91	28.80	30.64	30.79	32.05	31.55	31.75
Total	219.2	221.9	221.1	228.6	227.6	226.3	232.7	230.7	232.6
PRESSURES									
STEAM & WATER - KG/CM^2									
Economizer In.	133.5	133.3	133.1	133.3	133.1	133.1	133.2	133.1	133.1
Drum	132.6	133.3	132.7	133.6	133.6	133.4	133.1	133	133.2
SH - DESH In.	130.7	131.3	130.7	131.5	131.7	131.4	131.3	131.2	131.4
SH Out.	129.6	130.2	129.6	130.4	130.7	130.3	130.1	130.1	130.3
RH In.	23.76	23.83	24.04	24.32	23.97	24.25	24.46	24.46	24.32
RH Out.	22.50	22.57	22.78	23.06	22.71	22.99	23.20	23.20	23.06
AIR & GAS - CM. WG									
FD Fan Out.	7.11	6.35	6.86	6.60	5.33	8.13	9.40	6.60	6.86
"B" AH Air Out.	4.57	2.03	1.52	1.78	1.78	3.05	3.56	2.03	2.03
"B" AH Gas Out	-18.80	-18.80	-18.29	-19.30	-19.81	-19.56	-19.56	-19.81	-19.81
"D" Elev. Left Rear Fuel Air Comp.	1.016	0	.254	-.762	-.762	-.254	-3.56	-3.05	-.762
"A" Elev. Left Rear Fuel Air Comp.	-3.05	-3.05	-2.54	-3.30	-2.29	1.78	.254	1.27	3.56
Left Mill Duct at Windbox	3.81	1.52	1.27	.508	.762	2.03	2.79	.762	2.03
Mill Air Duct at "B" Elev. Mill	2.29	.254	.254	-1.27	-1.016	.254	1.52	-1.52	-1.16
Upper Furnace	-1.52	-1.52	-1.52	-1.52	-1.52	-1.52	-1.52	-1.52	-1.52
TEMPERATURES - °C									
STEAM & WATER									
SH Out.	509	502	507	518	514	518	523	516	512
SH DESH In.	418	416	418	424	440	429	440	445	443

TEST DATA
OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.	15	16	17	18	19	20	21	22	23
TEMPERATURES - °C									
STEAM & WATER									
SH DESH Out.	420	414	418	422	410	414	414	409	408
RH Out.	458	455	457	481	492	492	510	501	494
RH DESH In.	298	295	302	305	304	304	311	305	301
RH DESH Out.	295	287	292	303	302	304	311	306	301
Economizer In.	220	220	220	220	219	220	220	220	220
Economizer Out.	247	240	237	244	244	249	249	250	250
#5 HP Heater In.	180	181	181	181	182	183	184	185	184
#5 HP Heater Out.	218	219	220	220	220	219	219	220	220
#5 HP Heater Ext. In.	293	290	295	298	298	298	305	299	295
#5 HP Heater Drain	215	213	213	217	215	216	217	216	217
Spray Water	143	140	140	146	145	148	148	149	149
AIR & GAS									
AH Gas In.	300	299	301	301	302	301	303	302	304
AH Gas Out.	141	140	139	141	139	142	143	142	143
AH Air In.	47.2	36.7	35.0	38.4	31.7	43.9	44.4	37.2	39.5
AH Air Out.	260	262	262	261	263	261	263	259	263
Furnace Outlet (Avg.)	1121	1099	1105	1132	1188	1154	1221	1216	1199
Air Heater Leakage - %	11.19	12.24	10.53	11.32	10.96	11.15	10.53	11.25	13.01
AH Gas Side Efficiency - %	59.1	56.3	57.2	57.0	56.5	58.1	58.3	56.6	56.3
Unit Efficiency - %	90.0	89.8	89.7	89.6	89.3	90.2	90.1	89.0	89.1
PRODUCTS OF COMBUSTION - GR/10^6CAL.									
AH HOT SIDE									
Dry Air	1725	1657	1644	1675	1677	1679	1694	1751	1729
Wet Air	1743	1679	1665	1697	1699	1700	1716	1774	1751
Dry Products	1737	1717	1704	1733	1739	1737	1752	1810	1787
Wet Products	1780	1806	1794	1828	1837	1826	1843	1908	1884
AH COLD SIDE									
Dry Air	1933	1876	1830	1879	1876	1880	1885	1963	1971
Wet Air	1958	1900	1854	1904	1900	1904	1910	1989	1996
Dry Products	1994	1936	1891	1938	1938	1938	1943	2022	2029
Wet Products	2091	2028	1893	2034	2038	2030	2037	2123	2129
EXCESS AIR - %									
AH In.	28.5	27.1	25.6	26.6	24.8	25.4	25.4	27.9	28.1
AH Out.	44.0	43.8	39.9	42.1	39.6	40.4	39.5	43.4	46.0
FUEL ANALYSIS - %									
Carbon	65.9	66.6	65.4	65.2	64.3	69.3	67.5	65.4	66.0
Hydrogen	4.4	4.4	4.3	4.5	4.4	4.6	4.6	4.6	4.6
Nitrogen	1.1	1.1	1.1	1.4	1.1	.9	1.1	1.4	1.4
Oxygen	6.7	6.8	6.7	6.1	7.1	5.6	5.9	6.1	6.2
Sulfur	2.3	2.1	2.4	3.0	3.0	2.1	2.1	2.5	2.6
Moisture	7.4	6.7	7.3	8.0	9.6	5.8	5.4	7.8	7.9
Ash	12.2	12.3	12.8	11.8	10.5	11.7	13.4	12.2	11.3
HHV - CAL/G	6606	6844	6706	6711	6483	6994	6772	6511	6650

TEST DATA

OVERFIRE AIR TILT VARIATION — LOAD VARIATION AT OPTIMUM CONDITIONS

TEST NO.	24	25	26	27	34	29	30	31	32	33	34	35
DATE	7/30/74	7/30/74	7/30/74	7/30/74	7/30/74	7/30/74	7/30/74	7/31/74	7/31/74	7/31/74	7/31/74	8/1/74
TIME	9:47	11:20	13:10	15:30	16:30	18:07	21:05	10:20	12:30	21:50	23:35	1:10
UNIT LOAD - %	104	104	104	104	101	104	104	97	88	102	96	64
FLOWS - 10^3 KG/HR												
FEEDWATER	438	436	434	434	434	436	439	397	390	440	395	299
SH SPRAY (HEAT BALANCE)	6.36	6.36	21.00	13.6	15.90	1.82	18.77	18.59	4.09	8.61	5.05	1.27
MAIN STEAM	397	418	439	407	414	418	416	414	205	409	410	304
TURBINE LEAKAGE	18.13	18.13	18.5	18.03	18.09	18.66	18.64	18.18	17.45	18.27	14.0	9.41
RH EXTRACT	31.77	33.14	33.13	--	31.63	36.54	37.5	20.91	10.45	33.5	23.82	13.23
RH SPRAY (HEAT BALANCE)	.454	.454	.907	0.90	1.41	3.97	0	0.59	1.64	3.5	3.41	1.86
RH FLOW (CALC.)	368	387	384	--	387	390	398	281	185	360	276	183
RH FLOW (TEST)	366	383	381	383	387	394	398	273	185	365	275	187
AIR & GAS FLOWS - 10^3 KG/HR												
GAS ENT. AH	647	668	691	667	666	668	574	456	341	584	470	309
GAS LVG. AH	607	631	654	606	663	622	603	434	326	645	538	370
AIR ENT. AH	603	624	650	596	614	592	582	481	355	600	504	343
AIR LVG. AH	570	594	622	516	587	574	538	403	300	547	437	306
AH LEAKAGE	43.7	45.0	48.4	70.9	77.0	78.0	44.1	38.1	34.6	61.6	66.7	41.1
UNIT ABSORPTION - 10^6 KG-CAL/HR												
ECONOMIZER	12.93	12.90	12.36	12.70	3.78	10.33	8.68	1.95	1.27	4.21	3.70	5.44
FURNACE	145.19	152.59	142.53	144.47	142.06	154.17	150.04	111.67	73.80	141.80	120.61	81.14
DRUM - DESH	49.35	52.04	55.44	58.80	58.14	53.40	57.84	39.46	26.81	58.79	37.72	23.79
DESH - SH OUT.	97.84	95.90	80.94	84.25	33.84	84.39	90.10	64.72	38.97	86.51	20.20	13.81
RH	96.81	94.87	97.56	97.60	41.83	96.09	41.83	41.68	91.19	90.99	88.68	19.81
TOTAL	276.3	278.4	278.3	277.1	284.1	278.4	290.4	201.1	143.4	278.2	211.0	144.0
PRESSURES												
STEAM & WATER - KG/CM^2												
ECONOMIZER IN.	133.6	134.5	133.4	133.4	133.5	136.3	134.2	132.5	131.2	134.7	132.7	131.7
DRUM	133.2	133.3	133.7	133.7	133	134.6	134.6	132.4	132.4	134.6	132.7	132.2
SH - DESH IN.	131.7	131.8	131.2	131.2	131.3	132.1	132.7	131.0	131.0	132.2	131.3	131.2
SH OUT.	130.2	130.5	130.7	130.7	129.8	130.7	131.7	131.0	130.5	130.8	130.4	130.5
RH IN.	37	35.03	33.66	34.86	35.00	27.88	29.60	20.70	11.04	29.24	22.64	14.97
RH OUT.	29.06	28.80	28.47	28.17	28.61	28.47	28.54	21.65	11.27	27.84	21.37	14.2
AIR & GAS - CM. WG												
FD FAN OUT.	10.67	10.67	10.40	11.43	10.92	11.68	8.89	4.3	4.32	10.92	4.32	3.56
"B" AH AIR OUT	3.96	3.96	3.30	3.81	3.30	4.06	3.03	.762	1.016	4.32	.762	.508
"B" AH GAS OUT	-26.92	-25.91	-26.40	-26.42	-26.67	-26.42	-26.30	-17.05	-14.22	-26.67	-18.54	-13.46
"B" ELEV. LEFT REAR FUEL AIR COMP.	0	0	0	0	0	.254	.508	1.52	1.52	0	3.81	3.81
"A" ELEV. LEFT REAR FUEL AIR COMP.	-0.34	0.00	0.00	0.00	0.03	0.00	.762	-.254	.254	1.78	0	.254
LEFT MILL DUCT AT WINDBOX	0.33	1.78	0.00	0.00	0.03	4.06	1.016	-.254	.254	1.78	.254	.254
MILL AIR DUCT AT "B" ELEV. MILL	1.27	1.016	1.016	0.00	1.73	3.05	.508	0.03	.762	1.52	1.27	1.27
UPPER FURNACE	-1.52	-1.52	-1.016	-1.52	-1.52	-1.27	-1.52	-1.52	-1.016	-1.52	-1.27	-1.27
TEMPERATURES - °C												
STEAM & WATER												
SH OUT.	547	539	539	540	539	539	544	539	543	548	529	533
SH DESH IN.	464	468	474	471	496	511	476	457	456	467	446	436

TEST DATA

OVERFIRE AIR TILT VARIATION — LOAD VARIATION AT OPTIMUM CONDITIONS

TEST NO.	23	25	26	27	28	29	30	31	32	33	34	35
TEMPERATURES - °C												
STEAM & WATER												
FW DESH OUT.	443	440	439	441	441	448	439	433	436	434	439	436
RH OUT.	538	538	538	541	541	536	538	539	539	539	540	539
RH DESH IN.	340	336	341	340	340	341	340	337	343	345	345	341
RH DESH OUT.	343	339	344	433	340	344	343	341	347	350	350	345
ECONOMIZER IN.	241	241	241	240	240	240	240	214	197	247	260	303
ECONOMIZER OUT.	304	304	304	304	304	304	304	243	240	245	335	298
#7 HP HEATER IN.	190	191	191	193	193	191	194	180	184	189	190	185
#7 HP HEATER OUT.	205	205	205	205	205	205	205	205	205	205	205	205
#6 HP HEATER EXT. IN.	343	340	340	347	347	343	343	340	345	337	349	340
#6 HP HEATER DRAIN	207	207	208	207	206	207	205	210	190	207	211	194
SPRAY WATER	198	198	198	191	198	191	194	198	191	197	194	192
AIR & GAS												
AH GAS IN.	310	307	304	303	306	301	300	305	287	303	308	284
AH GAS OUT.	141	141	148	140	141	143	146	140	139	142	144	136
AH AIR IN.	36.1	37.8	37.9	36.7	36.6	37.0	28.0	22.8	25.0	33.6	33..	29.4
AH AIR OUT.	274	272	274	275	276	269	274	255	257	273	267	257
FURNACE OUTLET (AVG.)	1238	1221	1233	1232	1210	1188	1288	1238	116	1232	1177	1054
AIR HEATER LEAKAGE - %	8.07	11.54	11.70	12.75	13.15	14.37	8.70	8.36	10.14	10.56	14.14	12.49
AH GAS SIDE EFFICIENCY - %	57.4	57.4	57.6	55.8	54.6	56.9	56.2	54.9	56.5	56.4	5[illegible].4	54.0
UNIT EFFICIENCY - %	89.6	89.3	88.9	89.7	88.6	89.4	89.0	89.1	89.2	89.0	[illegible]	89.0
PRODUCTS OF COMBUSTION - $lb/10^6$ CAL.												
AH HOT SIDE												
DRY AIR	1626	1670	1708	1634	1664	1539	1610	1684	1885	1708	1804	1880
WET AIR	1647	1692	1730	1656	1686	1560	1631	1705	1909	1730	1827	1905
DRY PRODUCTS	1682	1730	1768	1695	1728	1593	1663	1744	1943	176[illegible]	1868	1939
WET PRODUCTS	1774	1827	1867	1789	1825	1748	1760	1837	2037	1867	1972	2036
AH COLD SIDE												
DRY AIR	1795	1878	1934	1860	1901	1847	1761	1835	2089	1903	2079	2131
WET AIR	1809	1900	1949	1884	1926	1871	1784	1859	2116	1907	2106	2159
DRY PRODUCTS	1841	1936	1984	1920	1965	1907	1820	1896	2147	1964	2143	2191
WET PRODUCTS	1934	2038	2086	2017	2065	1999	1919	1991	2243	2064	2251	2290
EXCESS AIR - %												
AH IN.	26.3	27.7	28.1	27.7	28.2	23.1	21.6	25.2	46.9	27.4	27.4	46.9
AH OUT.	.0	30.1	45.1	30.1	31.3	45.9	33.0	40.4	62.6	41.9	46.[illegible]	65.3
FUEL ANALYSIS - %												
CARBON	68.4	69.0	69.1	68.8	69.1	64.5	65.8	66.8	64.3	64.3	64.0	65.0
HYDROGEN	4.6	4.4	4.4	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.4
NITROGEN	1.0	1.0	1.0	1.1	1.0	1.0	1.1	1.1	1.0	1.0	1.1	1.[illegible]
OXYGEN	6.6	6.1	6.1	6.3	6.7	6.8	6.3	6.4	6.9	6.9	6.9	6.9
SULFUR	3.1	3.4	3.4	3.3	3.3	3.3	3.3	3.3	3.2	3.2	3.3	3.3
MOISTURE	7.0	6.9	6.9	7.4	6.7	8.0	7.1	7.5	7.1	9.6	9.7	9.6
ASH	11.1	11.1	11.0	10.8	10.8	13.1	13.7	10.9	13.3	10.7	11.0	10.2
HHV - CAL/G	6411	6494	6547	6450	6483	6260	6644	6583	6394	6617	6433	6893

BASELINE STUDY
BOARD DATA

Test No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Date	11-04-71	11-05-71	11-05-71	11-15-71	11-15-71	11-08-71	11-08-71	11-09-71	11-10-71	11-15-71	10-31-71	10-4-71	11-16-71	11-16-71
Time	15:17	10:37	15:20	10:05	10:37	10:37	15:17	13:04	10:50	07:40	13:50	14:00	9:50	
Load - MW	90	60	67	94	104	103	107	126	130	104	44	74	125	126
Fuels - Distillate														
No. 6														
1A2 Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1B2 Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2A2 Oil	460	280	324	810	470	495	485	460	460	480	460	460	460	468
Reheat Steam	460	280	324	810	470	495	485	460	460	470	460	0	460	468
Condensate	460	280	324	810	470	495	485	460	460	470	460	0	460	468
Superheat Spray	460	280	324	810	470	495	485	460	460	470	460	0	460	468
Reheat Spray	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feedwater	460	280	324	810	470	495	485	460	460	470	460	460	460	468
Furnace Steam Flow	460	280	324	810	470	495	485	460	460	470	460	460	460	468
Air Flow - Relative	460	280	324	810	470	495	485	460	460	470	460	460	460	468
Boilers														
Steam & Water - PSIG														
Hot Reheat Extraction														
4th	640	370	695	1350	1330	1310	1310	1340	1310	1310	668	775	1330	1330
5th	415	245	455	915	875	870	870	870	870	870	440	510	880	880
6th	276	160	296	570	560	560	560	560	560	560	280	331	560	560
7th	170	94	178	345	340	340	340	340	340	340	170	200	340	340
10th (Abs. Hdr = PSIG)	54	24	58	94	94	94	94	94	94	94	21.5	23	94	94
Star (In. Hg)	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.4	6.0	6.0	6.5	6.5	6.6	6.6
Feedwater Regulator Inlet	-1300	-1300	-1300	-1300	-1320	-1320	-1320	-1320	-1320	-1320	-1320	-1320	-1320	-1320
Feedwater	1940	1940	1940	1940	2000	2010	2005	2000	2005	2005	1930	1940	2000	2005
Drum	1830	1830	1830	1830	1910	1910	1910	1910	1910	1910	1830	1830	1910	1910
Turbine Throttle	1800	1800	1800	1800	1940	1940	1940	1940	1940	1940	1800	1800	1940	1940
Reheat Inlet	1600	1600	1600	1600	1800	1800	1800	1800	1800	1800	1600	1600	1800	1800
Reheat Bowl	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Exhaust (In. Hg)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Main Steam	1800	1800	1800	1800	1800	1800	1800	1800	1800	1800	1800	1800	1800	1800
Reheat Outlet	1600	1600	1600	1600	1800	1800	1800	1800	1800	1800	1600	1600	1800	1800
Light Oil Upper Burners	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Light Oil Lower Burners	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pressures														
Air & Gas - In. Wg														
2A FD Fan Discharge	1.8	1.0	1.0	3.1	4.0	3.0	6.8	4.0	4.1	6.0	1.5	1.5	4.9	5.8
2B FD Fan Discharge	1.8	1.0	1.0	3.0	4.0	3.8	6.0	4.0	4.0	5.2	1.1	1.2	4.2	5.2
2A Preheater Outlet Air	.7	.7	.6	.8	1.2	.5	2.5	1.5	0.3	0.5	.7	.4	1.5	2.2
2B Preheater Outlet Air	.8	.8	.6	.8	1.5	.8	2.8	1.5	1.0	2.5	.8	.5	1.5	2.0
Furnace Pressure	-.6	-.6	-.6	-.6	-.6	-.6	-.6	-.6	-.6	-.6	-.6	-.6	-.6	-.6
Superheater Cavity	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
Econ. Inlet	-2.7	-2.7	-2.4	-2.4	-3.4	-3.5	-3.4	-3.4	-3.5	-3.4	-1.0	-1.1	-1.7	-1.6
Economizer Outlet R.H.	-1.7	-1.7	-1.4	-1.4	-2.3	-2.8	-2.4	-2.6	-2.4	-2.1	-0.6	-0.8	-1.2	-1.3
Economizer Outlet L.H.	-1.6	-1.6	-1.5	-1.4	-2.6	-2.6	-2.9	-2.8	-2.7	-2.1	-0.5	-0.7	-1.1	-1.2
No. 2A Preheater Diff. Gas	1.3	1.2	1.4	1.4	1.4	1.5	1.4	1.4	1.4	1.4	1.3	1.3	1.4	1.4
No. 2B Preheater Diff. Gas	1.4	1.2	1.4	1.4	1.4	1.5	1.4	1.4	1.4	1.4	1.3	1.3	1.4	1.4
No. 2A I.D. Fan Suction	-6.4	-4.6	-4.1	-4.0	-13.8	-10.0	-15.0	-13.6	-10.5	-16.0	-4.0	-7.6	14.5	16.0
No. 2B I.D. Fan Suction	-6.2	-4.6	-4.0	-4.0	-13.6	-10.0	-14.8	-13.8	-10.5	-16.0	-4.0	-7.6	14.5	16.0
Pulverizer 2A Inlet Air	-1.5	-1.5	-1.5	-1.3	-1.3	-1.4	-1.1	-1.0	-1.4	-1.8	-1.4	-1.4	-1.3	-1.2
Exhauster 2A Discharge	13.2	13.4	13.3	13.0	14.3	10.8	13.5	11.6	12.5	13.5	12.3	12.4	13.5	13.7
Pulverizer 2B Inlet Air	-.6	-1.7	-1.7	-1.3	-1.4	-1.7	-1.5	-1.4	-1.6	-1.4	-1.6	-1.8	-1.4	-1.4
Exhauster 2B Discharge	13.1	13.4	13.4	13.2	13.0	10.2	13.0	11.5	10.2	13.0	12.8	12.7	12.8	13.2
Pulverizer 2C Inlet Air	-2.0	-2.0	-2.0	-1.6	-1.8	-1.5	-1.3	-1.8	-1.8	-1.8	-0.4	-0.3	-1.8	-1.7
Exhauster 2C Discharge	10.5	10.7	10.8	10.5	10.0	10.0	10.0	10.1	10.5	10.6	10.0	10.1	10.8	10.8
Pulverizer 2D Inlet Air	-1.7	-1.7	-1.7	-1.2	-2.4	-2.4	-1.8	-2.3	-2.4	-2.0	-1.2	-1.2	-2.4	-2.0
Exhauster 2D Discharge	0	0	0	0	10.1	10.0	10.2	11.8	10.0	13.0	0	0	10.0	10.3

BASELINE STUDY
BOARD DATA

BASELINE STUDY BOARD DATA

Test No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
A Mill Amps	40	40	38	36	38	40	40	39	38	40	40	38	40	39
B Mill Amps	38	39	41	37	44	42	41	40	43	41	38	34	40	44
C Mill Amps	40	38	38	40	38	40	40	40	40	40	40	33	40	40
D Mill Amps	0	0	0	0	0	41	41	41	41	40	0	0	40	40
Exhauster Damper Position - % Open (0 - 10 Scale)														
Mill 2A	11.4	11.2	11.3	9.7	7.7	6.0	6.0	5.4	6.0	5.0	5.0	7.0	6.0	6.0
Mill 2B	11.2	11.5	11.3	8.1	7.8	6.0	7.0	6.3	5.8	6.0	7.1	7.0	8.1	8.0
Mill 2C	11.3	11.5	11.5	6.6	7.0	4.4	4.8	6.6	6.7	6.4	6.0	6.0	5.8	5.8
Mill 2D	0	0	0	0	6.2	7.4	6.1	6.1	5.4	6.0	0	0	5.8	5.8
Pulverizer Feeder Dsp. - % Open (0 - 10 Scale)														
Mill 2A	4.1	4.8	4.4	5.7	5.0	4.4	4.6	4.8	5.1	5.0	4.7	4.5	5.2	5.3
Mill 2B	3.8	3.7	3.7	3.7	5.4	5.3	4.0	4.1	4.5	4.6	4.3	3.7	5.0	5.0
Mill 2C	4.2	4.0	4.0	3.6	5.4	4.1	4.4	5.0	5.8	5.6	5.4	5.4	5.8	5.8
Mill 2D	0	0	0	0	4.2	5.0	5.1	5.6	6.0	6.0	0	0	6.0	6.0
Spray Valve Positions - % Open														
SH Spray A	16	0	19	0	79	10	48	40	44	68	0	16	60	2
SH Spray B	16	0	19	0	0	0	10	40	36	52	0	16	54	66
RH Spray A	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RH Spray B	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burner Tilt Position - Degrees														
LR														
RR	+0	+0	+0	0	+4	+4	+4	+10	-20	-20	-9	+4	-22	-22
LF	+6	+13	+6	+8	+0.0	+4	+4	+6	-20	-20	-9	+4	-22	-22
RF	+6	+13	+6	+10	+6.0	+4	+4	+10	-20	-20	-9	+4	-22	-22
	+6	+13	+6	+10	+9.0	+4	+4	+7	-20	-20	-11	+4	-22	-22
Feedwater Valve - % Open (0-10 Scale)	8.1	8.1	8.1	8.0	12.0	11.4	11.4	10.0	10	10	10	10	9.8	9.8
Air Htr. 2A Recirc. Damper - % Open	37	38	39	39	51	44	40	34	30	30	35	36	34	34
Air Htr. 2B Recirc. Damper - % Open	50	51	50	50	58	49	42	*	36	27	*	*	36	*

BIASED FIRING STUDY

BOARD DATA

Test No.	15	16	17	18	19	20	21	22	23	24
Date	1-19-74	1-18-74	12-3-73	12-4-73	12-5-73	12-6-73	1-18-74	1-19-74	1-19-74	1-19-74
Time	09:10	18:24	11:07	01:30	23:50	02:30	20:30	15:45	13:30	11:30
Load - MW	66	96	100	103	99	102	94	64	64	166
Flows - 10^3 LBS/HR										
BFP 2A	0	0	0	0	0	0	0	0	0	0
BFP 2B	220	324	360	360	360	360	350	240	250	240
BFP 2C	230	382	384	385	403	403	400	210	200	210
Reheat Steam	635	770	770	790	770	770	760	650	640	640
Condensate	330	460	470	470	470	460	460	340	341	325
Superheat Spray	3.1	10.0	17.5	17.5	4.9	8.3	3.0	2.9	2.5	10.0
Reheat Spray	0	0	0	0	0	0	0	0	0	0
Feedwater	390	660	600	600	---	---	660	440	440	400
Primary Steam Flow	450	675	690	700	690	693	675	450	450	442
Air Flow - Relative	580	750	700	705	660	705	750	580	590	575
PRESSURES										
Steam & Water - PSIG										
1st Stage Extraction	1680	1000	1020	1040	1020	1030	1000	680	670	670
4th	210	315	322	328	320	320	315	213	212	210
12th	75	122	125	128	125	125	120	76	77	76
16th	21	39	40	40	38.5	39.5	37.0	20.0	20.5	20.5
19th (+In. Hg; + PSIG)	-11.5	0.0	0.0	0.0	0.0	0.0	0.0	-11.0	-10.5	-11.0
21st (In. Hg)	-21.0	-15..	-16.0	-16.0	-16.0	-16.2	-15.2	-20.5	-20.2	-21.0
Feedwater Regulator Inlet	2045	2000	1960	1980	1975	2000	1960	2050	2035	2025
Feedwater	1890	1920	1910	1920	1910	1925	1910	1890	1895	1890
Drum	1890	1915	1900	1920	1910	1925	1910	1900	1900	1900
Turbine Throttle	1845	1830	1810	1825	1825	1830	1830	1840	1845	1835
Reheat Inlet	199	308	317	321	316	317	308	200	201	199
Reheat Bowl	188	286	294	300	291	293	286	193	190	190
Exhaust (In. Hg)	-29.4	-28.5	-28.1	-28.2	-28.4	-28.4	-28.5	-29.0	-29.0	-29.2
Main Steam	1850	1850	1840	1850	1850	1850	1850	1850	1850	1850
Reheat Outlet	200	297	305	310	301	302	297	200	200	200
Light Oil Upper Burners	26	0	0	0	26	26	0	26	26	26
Light Oil Lower Burners	26	0	0	0	26	26	0	26	26	26
PRESSURES										
Air & Gas - In. Hg										
2A FD Fan Discharge	1.2	3.0	3.2	3.1	2.0	2.5	3.2	1.2	1.2	1.2
2B FD Fan Discharge	0.8	3.0	2.9	2.8	1.8	2.5	3.0	0.8	0.8	0.8
2A Preheater Outlet Air	-.5	1.0	1.0	1.0	.4	.6	1.2	-.5	-.5	-.5
2B Preheater Outlet Air	-.2	1.0	1.0	1.0	.4	.7	1.2	-.2	-.2	-.2
Furnace Pressure	-.45	-.5	-.47	-.5	-.48	-.5	-.4	-.45	-.5	-.4
Superheater Cavity	-1.0	-1.3	-1.3	-1.4	-1.3	-1.3	-1.2	-1.0	-1.0	-1.0
Econ. Inlet	-3.0	-4.2	-4.1	-4.3	-4.0	-4.2	-4.0	-3.0	-3.0	-3.1
Economizer Outlet A.H.	-4.0	-5.4	-5.3	-5.5	-5.0	-5.3	-5.2	-4.0	-4.0	-4.0
Economizer Outlet B.H.	-4.0	-5.3	-5.3	-5.4	-5.0	-5.3	-5.2	-3.8	-3.9	-4.0
No. 2A Preheater Diff. Gas	2.8	3.2	2.9	3.0	2.8	2.9	3.2	2.3	2.3	2.3
No. 2B Preheater Diff. Gas	2.0	2.4	2.6	2.7	2.3	2.4	2.4	1.9	1.9	1.9
No. 2A I.D. Fan Suction	-7.2	-10.5	-10.0	-10.2	-9.1	-9.8	-10.1	-7.1	-7.1	-7.1
No. 2B I.D. Fan Suction	-7.2	-10.0	-10.0	-10.5	-9.5	-10.0	-9.8	-7.2	-7.1	-7.1

BIASED FIRING STUDY

BOARD DATA

Test No.	15	16	17	18	19	20	21	22	23	24
PRESSURES (Cont'd)										
Air & Gas - In. wg										
Pulverizer 2A Inlet Air	-1.5	-1.2	-1.0	-.8	-1.4	-.7	-.7	-.7	-1.5	-1.4
Exhauster 2A Discharge	11.5	12.0	12.0	13.0	13.0	0	0	0	10.5	11.5
Pulverizer 2B Inlet Air	-1.4	-1.0	-1.5	-1.4	-.75	-1.4	-1.3	-2.0	-.7	-1.5
Exhauster 2B Discharge	11.2	13.2	13.0	12.8	0	12.9	13.2	12.0	0	11.5
Pulverizer 2C Inlet Air	-2.0	-1.0	-1.2	-.9	-1.5	-1.2	-1.0	-1.5	-1.5	-0.8
Exhauster 2C Discharge	10.9	12.0	12.5	0	12.9	12.1	12.3	12.0	11.5	0
Pulverizer 2D Inlet Air	-1.2	-1.2	-1.2	-1.6	-2.5	-1.8	-2.0	-2.3	-2.0	-2.8
Exhauster 2D Discharge	0	0	0	12.0	12.8	11.9	10.5	10.0	10.0	8.8
TEMPERATURES										
Air & Gas - °F										
Boiler Outlet Gas L.H.	640	649	642	649	639	645	646	637	637	646
Boiler Outlet Gas R.H.	651	660	659	661	650	658	650	640	642	651
Economizer Out Gas L.H.	569	598	591	595	579	589	590	561	561	571
Economizer Out Gas R.H.	573	591	590	594	578	585	580	561	561	572
Preheater 2A Outlet Gas	301	312	297	300	290	288	310	298	298	302
Preheater 2B Outlet Gas	301	285	297	300	290	278	278	302	300	302
Preheater 2A Inlet Air	81	109	99	99	71	62	108	85	86	82
Preheater 2B Inlet Air	79	102	98	93	69	62	102	85	85	81
Preheater 2A Outlet Air	511	520	517	520	512	519	515	502	505	515
Preheater 2B Outlet Air	519	503	520	522	518	515	495	510	510	519
Pulverizer 2A Inlet Air	465	478	480	484	480	480	110	110	460	478
Pulverizer 2A Internal	145	160	138	142	137	80	110	110	145	140
Pulverizer 2B Inlet Air	465	480	480	483	100	482	478	460	110	465
Pulverizer 2B Internal	140	160	145	144	100	162	155	150	110	140
Pulverizer 2C Inlet Air	445	462	480	100	475	479	460	460	480	95
Pulverizer 2C Internal	175	162	122	100	130	145	160	160	155	95
Pulverizer 2D Inlet Air	89	95	105	490	479	480	460	470	470	460
Pulverizer 2D Internal	89	95	105	152	125	143	142	180	140	165
TEMPERATURES										
Steam & Water - °F										
Feedwater	388	445	445	449	442	445	425	412	413	413
Economizer Water Outlet - L.H.	462	480	478	480	471	479	472	457	458	468
Economizer Water Outlet - R.H.	462	480	480	481	473	479	472	456	451	466
RH Desuph. In L.H.	574	596	585	609	577	611	551	505	515	575
RH Desuph. Out L.H.	574	596	585	609	577	611	551	505	515	575
RH Desuph. In R.H.	574	596	585	609	577	611	551	505	515	575
RH Desuph. Out R.H.	574	596	585	609	577	611	551	505	515	575
Superheat Out L.H.	1000	986	978	1006	967	996	941	928	939	1000
Superheat Out R.H.	1008	998	970	992	969	1009	937	921	930	998
Throttle Steam L.H.	998	985	970	995	965	1000	938	927	930	998
Throttle Steam R.H.	998	985	970	995	962	1000	938	920	930	998
Reheat Outlet L.H.	886	901	920	955	900	955	849	819	829	922
Reheat Outlet R.H.	941	961	885	909	861	904	867	828	841	946
Superheater Outlet	990	979	955	980	951	990	981	910	923	987
Reheater Outlet	913	930	920	950	895	950	866	879	840	942
Upper Valve Chest	975	965	952	971	939	1019	921	900	908	976
Lower Valve Chest	100	101	100	101	94	90	101	101	100	100
H.P. Exhaust	568	595	589	609	578	632	555	500	509	568
Reheat Bowl	918	937	918	937	885	975	870	830	840	932
Intermediate Exhaust	440	451	435	455	418	470	401	378	385	458
Condensate Temp.	95	105	107	106	104	103	106	97	97	95

BIASED FIRING STUDY

BOARD DATA

Test No.	15	16	17	18	19	20	21	22	23	24
S.H. Dewpt. In L.H.	845	811	848	870	809	850	800	805	805	876
S.H. Dewpt. Out L.H.	828	800	747	816	796	830	789	790	790	809
S.H. Dewpt. In R.H.	864	855	840	858	799	831	974	795	800	872
S.H. Dewpt. Out R.H.	851	820	792	809	770	788	786	790	791	821
MISCELLANEOUS										
F.D. Fan 2B RPM	420	540	550	560	520	540	520	430	420	420
F.D. Fan 2B RPM	470	540	560	560	520	540	530	490	470	470
I.D. Fan 2A RPM	360	530	430	430	380	410	530	370	370	360
I.D. Fan 2B RPM	340	535	440	440	380	420	535	340	350	340
Fan Damper Position - (0-12)										
FD Fan 2A	5.4	6.2	7.7	7.6	7.8	7.9	6.0	5.2	5.2	5.4
FD Fan 2B	5.8	6.0	7.8	7.8	7.8	7.9	5.8	5.2	5.8	5.8
ID Fan 2A	3.7	5.0	6.8	6.8	4.3	4.5	4.8	3.8	3.9	3.7
ID Fan 2B	3.8	4.0	6.8	6.8	4.1	4.4	4.6	3.5	3.7	3.7
Drum Level In. ± Norm; H_2O Level	-0.5	-0.5	-2.5	-1.0	-2.0	-1.0	-0.6	-0.5	-0.6	-0.6
A Mill AMPS	35	36	46	46	42	0	0	0	32	36
B Mill AMPS	36	35	39	42	0	42	36	31	0	37
C Mill AMPS	26	38	46	0	42	42	38	35	35	0
F Mill AMPS	0	0	0	43	44	44	39	36	37	28
Elevator Damper Position - Open (0-12 Scale)										
Mill 2E	52	56	56	80	82	0	0	0	58	50
Mill 2D	54	80	78	82	0	79	78	60	0	52
Mill 2C	32	57	80	0	80	56	53	50	41	0
Mill 2F	0	0	0	63	83	54	49	49	42	28
Pulverizer Feeder Cap - (20-120 Scale)										
Mill 2E	52	56	57	64	54	0	0	0	38	50
Mill 2D	52	56	47	58	0	50	54	35	0	50
Mill 2C	20	55	56	0	62	54	53	49	50	0
Mill 2F	0	0	0	64	54	55	50	50	52	20
Spray Valve Positions - Open										
SH Spray L	0	40	42	47	37	40	0	0	0	34
SH Spray R	0	41	41	41	17	20	0	0	0	35
RH Spray L	0	0	0	0	0	0	0	0	0	0
RH Spray R	0	0	0	0	0	0	0	0	0	0
Burner Tilt Positions - Degrees										
LR	-10	0	-18	-9	-9	-2	0	0	0	-18
RR	-13	+1	-18	-10	-9	-2	+8	0	0	-19
LF	-11	0	-18	-10	-9	-2	+10	0	0	-17
RF	-10	-1	-19	-10	-10	-2	+10	0	0	-16
Feedwater Valve - Open (0-12 Scale)	7.8	12.0	12.0	12.0	12.0	8.4	12.0	7.6	7.9	8.0
Fr Htr. 2A Recirc. Damper - Open	39	39	32	32	44	20	37	37	36	39
Fr Htr. 2B Recirc. Damper - Open	32	41	34	31	32	20	40	32	32	32

BOARD DATA

BASELINE STUDY AFTER MODIFICATION

BOARD DATA

BASELINE STUDY AFTER MODIFICATION

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
TEMPERATURES														
AIR & GAS - F														
BOILER OUTLET GAS E.H.	614	607	597	605	597	647	658	662	646	650	619	640	651	652
BOILER OUTLET GAS R.H.	607	616	582	630	602	657	645	647	661	662	606	650	662	663
ECONOMIZER OUT GAS E.H.	550	554	539	556	575	594	609	614	598	606	547	561	604	609
ECONOMIZER OUT GAS R.H.	575	584	560	598	574	600	611	617	615	610	557	589	610	612
PREHEATER 2A OUTLET GAS	340	347	335	358	338	366	387	398	390	388	348	368	377	380
PREHEATER 2B OUTLET GAS	373	383	379	400	381	405	396	398	394	396	370	390	395	398
PREHEATER 2A INLET AIR	91	92	87	94	100	100	107	99	107	120	96	98	110	113
PREHEATER 2B INLET AIR	93	98	90	98	101	104	109	93	101	109	101	101	108	110
PREHEATER 2A OUTLET TEM	472	471	474	496	504	508	493	516	506	504	440	466	518	501
PREHEATER 2B OUTLET AIR	473	475	495	491	510	510	506	516	520	509	485	496	517	506
PULVERIZER 2A INLET AIR	319	320	320	421	397	430	421	410	360	410	420	410	440	430
PULVERIZER 2A INTERNAL	140	140	160	150	140	140	155	140	140	160	145	155	160	155
PULVERIZER 2B INLET AIR	420	421	420	440	440	450	440	465	475	440	405	435	455	440
PULVERIZER 2B INTERNAL	150	160	150	140	145	140	145	160	140	160	145	155	150	155
PULVERIZER 2C INLET AIR	410	400	430	425	475	430	420	470	470	436	410	420	440	435
PULVERIZER 2C INTERNAL	160	160	165	150	160	130	160	150	140	160	170	160	150	155
PULVERIZER 2D INLET AIR	80	85	80	80	475	450	475	465	475	435	80	80	480	480
PULVERIZER 2D INTERNAL	80	85	80	80	175	155	175	170	175	180	80	80	175	175
TEMPERATURES														
STEAM & WATER - F														
FEEDWATER	378	378	406	440	470	470	470	472	472	457	411	411	460	460
ECONOMIZER WATER OUTLET - E.H.	380	390	360	460	490	486	490	494	490	489	447	471	489	490
ECONOMIZER WATER OUTLET - R.H.	430	429	403	460	490	485	490	490	490	489	441	470	489	490
RH DESUPH. IN E.H.	595	561	562	547	638	629	610	630	630	691	520	562	621	630
RH DESUPH. OUT E.H.	595	561	560	547	638	629	610	630	630	621	520	562	621	630
RH DESUPH. IN R.H.	595	561	560	547	638	629	610	630	630	621	520	562	621	630
RH DESUPH. OUT R.H.	595	561	560	547	638	629	610	630	630	621	520	562	621	630
SUPERHEAT OUT E.H.	907	870	890	896	982	979	962	972	970	968	935	980	972	982
SUPERHEAT OUT. R.H.	915	870	898	941	980	978	961	971	970	968	941	985	968	982
THROTTLE STEAM E.H.	916	870	898	941	978	977	960	970	970	965	941	982	968	980
THROTTLE STEAM R.H.	915	860	894	941	980	975	961	970	969	972	941	985	970	982
REHEAT OUTLET E.H.	837	790	810	858	930	926	920	941	930	930	858	947	938	942
REHEAT OUTLET R.H.	811	790	810	850	905	907	900	908	917	908	850	930	911	913
SUPERHEATER OUTLET	917	875	937	940	980	976	964	978	980	975	945	987	975	985
REHEATER OUTLET	815	755	800	850	904	917	910	905	916	902	855	936	904	930
UPPER VALVE CHEST	860	800	909	870	903	908	897	906	901	896	885	909	891	902
LOWER VALVE CHEST	96	96	90	97	105	93	101	100	108	101	99	98	100	100
H.P. EXHAUST	470	430	490	---	600	---	---	595	595	---	491	530	---	---
REHEAT DRUM	801	760	881	850	830	882	880	901	886	875	830	910	875	879
INTERMEDIATE EXHAUST	650	610	611	---	619	---	---	620	612	---	575	631	---	---
CONDENSATE TEMP.	110	107	107	107	107	119	119	107	107	115	107	107	120	119
S.H. DESUPH. IN E.H.	743	701	842	770	895	816	850	850	901	891	771	908	845	842
S.H. DESUPH. OUT E.H.	736	696	807	760	905	834	808	802	876	811	769	788	809	813
S.H. DESUPH. IN R.H.	743	709	840	765	901	810	842	839	915	850	762	899	845	847
S.H. DESUPH. OUT R.H.	740	701	809	767	810	901	800	800	800	890	752	782	811	806
MISCELLANEOUS														
I.D. FAN 2A RPM	620	580	595	600	686	690	685	686	660	630	490	530	680	630
I.D. FAN 2B RPM	620	580	595	600	675	690	680	675	660	660	490	595	680	645
F.D. FAN 2A RPM	450	420	450	490	630	530	680	600	520	580	350	460	580	640
F.D. FAN 2B RPM	487	280	440	490	625	535	680	600	540	595	340	460	585	645
SEC. DAMPER POSITION - (0-10)														
ID FAN 2A	8.1	7.8	8.0	7.8	10	7.8	10.0	10	10	10.0	7.0	8.2	10	10
ID FAN 2B	8.1	7.8	8.0	7.1	10	10.0	10.0	10	10	10.0	7.0	8.0	10	10
FD FAN 2A	7.9	8.4	8.0	8.1	10	8.4	10.0	10	10	10.0	8.3	8.3	10	10
FD FAN 2B	7.9	8.8	8.0	8.4	10	8.8	10.0	10	10	10.0	8.3	8.3	10	10
DRUM LEVEL IN. E.H. DRUM (0-10 Level)	-4.0	-4.0	-4.0	-4.0	-4.0	-4	-4	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.2

BOARD DATA

BASELINE STUDY AFTER MODIFICATION

BOARD DATA

OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.	15	16	17	18A	19	20	21	22	23
Date	7/10/74	7/10/74	7/10/74	7/12/74	7/11/74	7/11/74	7/12/74	7/12/74	7/12/74
Time	0:00	2:15	4:00	7:25	4:35	23:10	1:24	3:30	4:45
Load - Mw	97	98	100	100	100	100	102	102	102
FLOWS - 10^3LBS/HR									
BFP 2A	0	0	0	0	0	0	0	0	0
BFP 2B	415	415	420	425	410	420	420	420	425
BFP 2C	360	360	360	365	355	360	360	365	365
Reheat Steam	810	810	820	835	805	820	830	830	830
Condensate	525	530	535	535	525	540	535	540	540
Superheat Spray	30.5	30.5	30.0	29.8	36.0	31.9	33.0	34.0	34.0
Reheat Spray	0	0	0	0	0	0	0	0	0
Feedwater	690	690	690	700	650	685	670	670	670
Primary Steam Flow	725	715	720	725	715	725	725	725	725
Air Flow - Relative	700	660	660	675	680	720	720	680	700
PRESSURES									
STEAM & WATER - PSIG									
1st Stage Extraction	1060	1060	1060	1080	1060	1070	1080	1080	1080
8th	334	338	340	340	340	340	342	348	347
12th	131	130	133	135	132	135	136	136	136
16th	40	40	40	41	41	41	42	42	42
19th (-In. Hg; +PSIG)	0	0	0	0	0	0	0	0	0
21st (In. Hg)	-15.2	-15.2	-15.1	-15.2	-15.6	-15.2	-15.2	-15.2	-15.2
Feedwater Regulator Inlet	2000	2010	2010	2000	2000	2000	2000	2010	2000
Feedwater	1950	1950	1950	1950	1940	1940	1940	1950	1940
Drum	1930	1930	1935	1930	1920	1915	1920	1925	1925
Turbine Throttle	1850	1850	1850	1845	1835	1835	1835	1840	1835
Reheat Inlet	329	330	330	332	330	330	335	340	339
Reheat Bowl	304	305	306	309	305	308	310	314	313
Exhaust (In. Hg)	-27.3	-27.6	-27.6	-27.3	-27.4	-27.4	-27.3	-27.3	-27.3
Main Steam	1870	1870	1870	1865	1850	1850	1850	1855	1860
Reheat Outlet	315	315	320	321	319	320	322	325	325
Light Oil Upper Burners	0	0	0	23	23	23	23	23	23
Light Oil Lower Burners	0	0	0	25	25	25	25	25	25
PRESSURES									
AIR & GAS - IN. WG									
2A FD Fan Discharge	4.2	3.1	3.1	3.0	3.0	3.9	4.0	3.0	3.4
2B FD Fan Discharge	4.0	2.7	2.9	2.5	2.7	3.3	3.8	2.7	3.0
2A Preheater Outlet Air	2.0	1.0	1.0	.8	1.0	1.5	1.8	1.8	1.0
2B Preheater Outlet Air	2.0	1.0	1.1	.8	1.0	1.5	1.8	1.8	1.1
Furnace Pressure	-.48	-.48	-.48	-.45	-.48	-.45	-.45	-.45	-.46
Superheater Cavity	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.3
Economizer Inlet	-4.0	-4.0	-4.0	-4.2	-4.2	-4.1	-4.3	-4.4	-4.4
Economizer Outlet RH	-5.3	-5.2	-5.2	-5.5	-5.5	-5.5	-5.6	-5.8	-5.7
Economizer Outlet LH	-5.3	-5.2	-5.2	-5.5	-5.5	-5.5	-5.6	-5.8	-5.7
No. 2A Preheater Diff. Gas	2.9	2.9	2.9	3.0	2.9	3.0	3.0	3.1	3.1
No. 2B Preheater Diff. Gas	2.4	2.3	2.35	2.4	2.4	2.4	2.4	2.6	2.6
No. 2A ID Fan Suction	10.0	10.0	10.0	10.5	10.4	10.3	10.5	11.0	11.0
No. 2B ID Fan Suction	10.0	10.0	10.0	10.5	10.5	10.3	10.7	11.0	11.0
Pulverizer 2A Inlet Air	-.7	-.7	-.7	-1.7	-.7	-.7	-1.1	-1.4	-1.25
Exhaust 2A Discharge	1.0	1.0	.9	0	.8	1.0	11.5	12.0	12.0
Pulverizer 2B Inlet Air	-.9	-1.2	-1.2	-1.0	-1.0	-.95	-.8	-.9	-.75
Exhauster 2B Discharge	10.0	10.0	10.0	11.5	10.2	11.5	11.5	11.5	12.0
Pulverizer 2C Inlet Air	-3.2	-3.3	-3.3	-2.5	-2.1	-2.6	-2.4	-2.4	-2.4
Exhauster 2C Discharge	11.0	11.0	11.0	11.0	11.5	11.2	11.5	11.5	12.0
Pulverizer 2D Inlet Air	-1.8	-2.0	-2.0	-1.4	-1.1	-1.75	-1.2	-1.2	-1.2
Exhauster 2D Discharge	11.0	11.0	11.2	11.2	12.0	11.3	0	0	0
TEMPERATURES									
AIR & GAS - °F									
Boiler Outlet Gas LH	639	638	639	640	641	640	645	645	645
Boiler Outlet Gas RH	646	648	649	649	650	648	652	652	652
Economizer Outlet Gas LH	571	571	572	572	577	573	578	580	579
Economizer Outlet Gas RH	572	574	578	579	582	579	583	589	586
Preheater 2A Outlet Gas	292	292	292	289	291	289	290	290	290
Preheater 2B Outlet Gas	292	292	291	290	287	297	299	298	298
Preheater 2A Inlet Air	122	98	92	95	91	105	103	92	98
Preheater 2B Inlet Air	132	98	95	99	91	110	111	98	101
Preheater 2A Outlet Air	489	495	498	492	500	489	492	498	495
Preheater 2B Outlet Air	492	501	501	500	502	500	505	509	507
Pulverizer 2A Inlet Air	100	90	80	80	80	100	410	420	425
Pulverizer 2A Internal	100	90	80	80	80	100	160	140	140
Pulverizer 2B Inlet Air	435	440	440	440	440	440	440	445	445
Pulverizer 2B Internal	140	140	140	150	130	160	160	140	150
Pulverizer 2C Inlet Air	420	420	420	440	440	440	440	450	455
Pulverizer 2C Internal	145	140	140	160	155	160	170	160	155
Pulverizer 2D Inlet Air	440	440	445	450	460	455	100	100	80
Pulverizer 2D Internal	142	140	140	160	155	160	100	100	80

BOARD DATA

OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.	15	16	17	18A	19	20	21	22	23
TEMPERATURES									
STEAM & WATER - °F									
Feedwater	445	445	445	450	447	450	450	450	450
Economizer water Outlet - LH	469	469	470	471	472	472	478	478	477
Economizer water Outlet - RH	469	469	470	470	472	472	477	478	477
RH DESH Inlet LH	572	567	574	585	582	585	600	589	582
RH DESH Outlet LH	572	567	574	585	582	585	600	589	582
RH DESH Inlet RH	572	567	574	585	582	585	600	589	582
RH DESH Outlet RH	572	567	574	585	582	585	600	589	582
Superheat Outlet LH	960	945	952	961	959	961	981	968	960
Superheat Outlet RH	959	942	952	965	962	969	988	968	962
Throttle Steam LH	955	940	950	966	959	965	985	965	961
Throttle Steam RH	950	938	948	968	968	975	990	969	960
Reheat Outlet LH	890	872	889	897	917	905	940	930	921
Reheat Outlet RH	860	848	859	889	907	891	929	912	905
Superheater Outlet	965	950	957	975	970	975	990	975	970
Reheater Outlet	855	845	854	889	907	895	928	915	905
Upper Valve Chest	899	890	898	920	911	905	929	920	910
Lower Valve Chest	101	101	100	101	102	105	105	102	101
HP Exhaust	549	539	545	560	554	555	575	565	557
Reheat Bowl	840	837	845	872	892	870	909	903	890
Intermediate Exhaust	384	375	380	410	419	405	430	422	417
Condensate Temperature	119	119	119	120	120	121	121	120	120
SH DESH Inlet LH	809	800	808	812	840	815	841	843	841
SH DESH Outlet LH	795	789	792	800	781	784	788	772	774
SH DESH Inlet RH	799	790	796	805	832	813	839	842	837
SH DESH Outlet RH	788	780	785	795	779	787	789	778	775
MISCELLANEOUS									
ID Fan 2A RPM	560	550	540	560	560	570	575	580	580
ID Fan 2B RPM	560	540	540	560	560	560	570	580	580
FD Fan 2A RPM	540	450	450	450	460	500	520	450	480
FD Fan 2B RPM	540	460	460	460	470	500	520	460	480
FAN DAMPER POSITIONS (0-12)									
ID Fan 2A	12+	12+	12+	12+	12+	12+	12+	12+	12+
ID Fan 2B	12+	12+	12+	12+	12+	12+	12+	12+	12+
FD Fan 2A	9.8	8.2	8.2	12+	6.2	12	12	12	12+
FD Fan 2B	9.6	8.2	8.2	12+	5.9	12	12	12	12+
Drum Level In. + Norm. H_2O Level	-4.5	-4.5	-4.5	-4.5	-4.5	-4.5	-4.5	-4.5	-4.5
2A Mill Amps	0	0	0	0	0	0	36	36	36
2B Mill Amps	37	36	36	36	37	37	38	37	37
2C Mill Amps	36	36	36	36	36	36	38	38	38
2D Mill Amps	41	41	42	38	41	40	0	0	0
EXHAUSTER DAMPER POSITION - % OPEN									
0-12 SCALE									
Mill 2B	0	0	0	0	0	0	4.8	5.0	5.3
Mill 2C	4.6	4.5	4.8	8.6	8.4	8.4	8.4	8.4	8.4
Mill 2C	4.4	4.4	4.6	5.2	4.4	4.8	4.8	5.0	5.4
Mill 2D	4.4	4.4	4.6	4.6	4.4	4.4	0	0	0
PULVERIZER FEEDER CAP. - % OPEN									
0-12 SCALE									
Mill 2A	0	0	0	0	0	0	4.8	5.0	5.4
Mill 2B	4.8	4.4	4.6	5.2	5.2	4.3	4.8	5.0	5.4
Mill 2C	4.9	4.8	5.2	5.8	5.7	4.8	5.3	5.5	5.9
Mill 2D	4.5	4.6	4.8	4.8	5.4	4.4	0	0	0
SPRAY VALVE POSITION - % OPEN									
SH Spray L	0	0	0	0	52	36	50	60	60
SH Spray R	0	0	0	0	52	36	50	60	60
RH Spray L	0	0	0	0	0	0	0	0	0
RH Spray R	0	0	0	0	0	0	0	0	0
BURNER TILT POSITION - DEGREES									
LR	-2	-2	-2	0	0	0	0	0	0
RR	0	0	0	0	+1	+2	+2	+2	+2
LF	0	0	0	0	0	+2	+2	+2	+1
RF	-1	-1	-1	0	-1	0	0	0	0
Feedwater Valve - % Open (0-12 Scale)	12+	12+	12+	12+	12+	12+	12+	12+	12+
Air Htr. 2A Recirc. Damper - % Open	40	29	29	32	0	32	32	32	32
Air Htr. 2B Recirc. Damper - % Open	40	29	26	35	0	32	34	34	34

BOARD DATA

OVERFIRE AIR

TILT VARIATION

LOAD VARIATION AT

OPTIMUM CONDITIONS

	A	B	C	D	E	F	G	H	I	J	K	L
DATE	10/24/73	10/25/73	11/7/73	11/8/73	11/9/73	11/10/73	11/30/73	12/31/73	1/31/74	2/28/74	3/31/74	4/1/74
TIME	1540	1500	1040	1120	1610	1600	2130	1010	2130	2100	2035	1130
LOAD - MW	173	174	174	176	176	174	176	97	69	120	95	64
FLOWS - 10³ LB/HR												
SH A	0	0	0	0	0	0	0	0	0	0	0	0
SH 2A	0	0	0	0	0	0	0	0	0	0	0	0
SH 2B	500	500	500	500	500	500	500	0	300	500	325	225
REHEAT STEAM	450	450	450	450	450	450	450	450	700	400	225	225
CONDENSATE	900+	900+	900+	900+	900+	900+	900+	810	665	900+	730	660
SUPERHEAT SPRAY	650	640	650	650	650	650	650	480	350	675	480	350
REHEAT SPRAY	43.0	41.0	40.0	41.0	42.0	41.5	41.0	33.5	31.0	33.5	30.0	31.0
FEEDWATER	0	0	0	0	0	0	0	0	0	0	0	0
PRIMARY STEAM FLOW	650	650	650	650	650	650	650	650	400	740	620	300
AIR FLOW - RELATIVE	695	715	695	695	695	695	695	680	455	695	675	445
	695	737	671	734	785	810	780	635	540	800	620	510
PRESSURES												
STEAM & WATER - PSIG												
1ST STAGE EXTRACTION	1300	1260	1300	1300	1319	1341	1336	1013	645	1320	1018	680
4TH	420	405	420	420	420	421	420	304	210	413	321	215
7TH	168	170	170	170	170	171	172	129	79	170	127	76
10TH	56	56	56	56	56	55.5	56.0	39	22	55	38	21.5
10TH (-IN. HG + PSIG)	6.3	6.0	6.0	6.0	6.0	6.0	6.0	-1.0	-12	6.0	0.0	12
DSH (IN. HG)	-10.5	-10.5	-10.5	-10.5	-10.4	-10.0	-10.5	-16.0	-20.0	-10.5	-16.0	-20.0
FEEDWATER REGULATOR INLET	3030	3000	3000	3000	3010	3040	3040	2000	1440	3060	2010	1960
FEEDWATER	1960	1950	1950	1950	1940	1950	1960	1395	1005	1960	1360	1910
DRUM	1930	1900	1930	1905	1915	1940	1940	1310	1000	1950	1920	1900
TURBINE THROTTLE	1805	1805	1805	1820	1800	1805	1805	1835	1850	1835	1850	1850
REHEAT INLET	411	410	411	417	418	415	418	315	204	411	311	200
REHEAT DELTA	385	386	380	384	385	381	384	290	196	380	290	191
EXHAUST (IN. HG)	-27.2	-27.1	-27.1	-27.1	-27.0	-27.0	-27.0	-27.8	-27.8	-27.0	-27.4	-27.7
MAIN STEAM	1850	1850	1850	1850	1850	1850	1860	1865	1865	1865	1865	1865
REHEAT OUTLET	937	938	933	938	938	935	938	935	200	931	930	930
LIGHT OIL UPPER BURNERS	0	0	0	0	0	0	0	0	24	23.5	23.5	23.5
LIGHT OIL LOWER BURNERS	0	0	0	0	0	0	0	0	25	25.0	25.0	25.0
PRESSURES												
AIR & GAS - IN. WG												
DA FD FAN DISCHARGE	4.9	4.8	4.9	4.9	4.6	5.1	4.0	2.5	1.3	4.9	2.5	1.5
DB FD FAN DISCHARGE	4.5	4.6	4.5	4.4	4.5	5.0	3.9	2.0	1.1	4.5	2.0	1.0
DA PREHEAT OUTLET AIR	1.5	1.7	1.9	1.9	1.5	2.0	1.0	.5	.3	1.5	.5	.2
DB PREHEATER OUTLET AIR	1.5	1.7	1.9	1.9	1.0	2.0	1.0	.5	.5	1.5	.5	.2
FURNACE PRESSURE	-.07	-.01	-.175	-.15	-.18	-.05	-.48	-.405	-.405	-.35	-.5	-.45
SUPERHEATER CAVITY	-1.1	-1.2	-1.0	-1.0	-1.0	-1.0	-1.3	-1.0	-1.0	-1.5	-1.1	-1.0
ECON. INLET	-0.6	-0.6	-0.7	-0.7	-0.7	-0.5	-0.6	-0.6	-0.3	-0.4	-0.7	-0.7
ECONOMIZER OUTLET R.H.	-7.1	-7.1	-7.0	-7.1	-7.0	-7.1	-7.9	-5.4	-4.1	-7.2	-6.1	-3.9
ECONOMIZER OUTLET L.H.	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.8	-5.4	-4.0	-7.5	-6.1	-3.8
NO. 2A PREHEATER DIFF. GAS	3.9	4.0	4.0	4.0	3.9	4.0	3.9	2.8	1.1	4.0	2.8	2.0
NO. 2B PREHEATER DIFF. GAS	3.5	3.6	3.4	3.5	3.4	3.4	3.5	2.4	1.7	3.6	2.3	1.6
NO. 2A I.D. FAN SUCTION	14.4	14.4	14.5	14.5	14.0	14.7	14.5	10.0	7.5	14.7	10.0	7.1
NO. 2B I.D. FAN SUCTION	14.0	14.0	14.0	14.0	14.3	14.0	14.5	10.1	7.2	14.0	10.0	6.8
PULVERIZER 2A INLET AIR	-1.1	-1.1	-1.0	-1.0	-1.0	-1.0	-1.4	-1.4	-1.05	-1.05	-1.4	-1.4
EXHAUSTER 2A DISCHARGE	10.0	10.6	10.5	10.0	10.0	10.7	10.0	10.0	10.5	10.2	10.5	10.9
PULVERIZER 2B INLET AIR	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.1	-1.0
EXHAUSTER 2B DISCHARGE	10.0	10.0	9.8	9.9	9.8	9.4	9.9	9.5	10.0	9.9	10.0	10.6
PULVERIZER 2C INLET AIR	-3.0	-3.0	-2.9	-2.9	-2.7	-2.6	-3.4	-3.0	-1.8	-3.0	-3.6	-1.0
EXHAUSTER 2C DISCHARGE	10.0	10.0	10.0	10.0	10.0	10.5	11.0	11.5	?	10.0	10.0	?
PULVERIZER 2D INLET AIR	-2.0	-1.1	-1.9	-2.0	-1.70	-1.6	-2.0	-1.2	-1.2	-1.5	-1.2	-1.0
EXHAUSTER 2D DISCHARGE	10.5	11.0	10.7	11.1	11.5	11.5	10.0	?	?	11.0	?	?

BOARD DATA

OVERFIRE AIR TILT VARIATION

LOAD VARIATION AT OPTIMUM CONDITIONS

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12
CONDITIONS												
AIR & GAS -												
Stack Outlet Gas L.H.	----	1014	1011	1010	1011	1011	1008	1010	1010	1010	1010	1008
Stack Outlet Gas R.H.	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Economizer Out Gas L.H.	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Economizer Out Gas R.H.	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Preheater Gs Outlet Gas	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Preheater Gs Outlet Gas	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Pulverizer Gs Inlet Air	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Pulverizer Gs Inlet Air	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Preheater Gs Outlet Air	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Preheater Gs Outlet Air	----	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Pulverizer Gs Inlet Air	1014	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Pulverizer Gs Inlet Air	1014	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Pulverizer Gs Inlet Air	1014	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Pulverizer Gs Inlet Air	1014	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Pulverizer Gs Inlet Air	1014	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
Pulverizer Gs Inlet Air	1014	1014	1011	1010	1011	1011	1008	1010	1011	1010	1010	1008
TEMPERATURES												
STEAM & WATER - °F												
Feedwater	361	361	360	361	361	361	360	361	361	361	361	361
Economizer Water Outlet - L.H.	----	600	600	600	600	600	600	600	600	600	600	600
Economizer Water Outlet - R.H.	----	600	600	600	600	600	600	600	600	600	600	600
RH Desuph. In L.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
RH Desuph. Out L.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
RH Desuph. In R.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
RH Desuph. Out R.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Superheat Out L.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Superheat Out R.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Throttle Steam L.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Throttle Steam R.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Reheat Outlet L.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Reheat Outlet R.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Superheater Outlet	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Reheater Outlet	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Upper Valve Chest	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Lower Valve Chest	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
H.P. Exhaust	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Reheat Row	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Intermediate Exhaust	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Condensate Temp.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
S.H. Desuph. In L.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
S.H. Desuph. Out L.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
S.H. Desuph. In R.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
S.H. Desuph. Out R.H.	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
MISCELLANEOUS												
I.D. Fan 1A RPM	690	690	690	690	690	690	690	560	480	690	540	460
I.D. Fan 1B RPM	680	670	670	680	680	680	679	560	480	670	540	460
F.D. Fan 2A RPM	560	570	590	565	570	600	540	440	400	570	410	370
F.D. Fan 2B RPM	570	570	590	570	580	600	540	440	400	570	400	370
Fan Damper Position - (0-10)												
ID Fan 1A	10+	10+	10+	10+	10+	10+	10+	7.0	5.8	10+	7.4	6.0
ID Fan 1B	10+	10+	10+	10+	10+	10+	10+	7.0	5.8	10+	7.0	6.0
FD Fan 2A	10+	10+	10+	10+	10+	10+	10+	4.3	3.8	11.8	5.0	3.6
FD Fan 2B	10+	10+	10+	10+	10+	10+	10+	4.3	3.8	11.8	5.0	3.6
Draft Level in. H2O, R.H. Furnace	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2

BOARD DATA

OVERFIRE AIR TILT VARIATION

LOAD VARIATION AT OPTIMUM CONDITIONS

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

RIGHT WALL CENTERLINE TUBE RATES

TC #		1 *	3	5	7	9	13	22	44	47	57	60	62	64
ELEVATION		118'-6"	107'-6"	96'-6"	85'-6"	74'-6"	63'-6"	64'-7"	59'-7"	54'-0"	49'-11"	45'-7"	35'-7"	25'-7"
TEST	1	2.02	3.56	7.43	8.81	10.33	9.07	1.28	---	---	8.54	4.08	3.30	---
	2	2.36	3.64	8.63	10.07	13.13	9.35	.86	---	---	6.51	5.39	3.12	---
	3	1.33	2.85	5.18	7.02	8.08	7.55	.83	---	---	9.66	9.93	4.13	---
	4	3.01	5.36	12.23	1.25	2.76	14.88	5.10	---	---	13.29	7.73	4.31	---
	5	3.78	7.19	10.90	10.90	22.55	7.46	6.33	---	---	18.85	20.96	12.49	---
	6	4.41	7.30	13.66	1.83	3.37	16.04	7.83	---	---	20.81	14.45	10.21	---
	7	3.73	5.04	10.06	1.19	2.18	7.67	8.73	12.18	---	27.78	11.38	14.56	---
	8	4.59	8.28	11.45	8.54	21.78	5.11	4.06	---	---	10.13	13.04	15.70	---
	9	6.26	9.96	14.95	15.52	23.46	15.52	6.26	---	---	8.63	12.34	15.26	---
	10	5.14	5.66	12.27	7.51	6.45	10.15	9.36	---	---	24.18	6.98	12.80	---
	11	4.16	4.95	6.26	6.79	6.53	4.43	6.00	---	---	11.56	6.53	6.53	---
	12	4.15	5.46	6.61	6.61	5.98	5.72	5.72	---	---	11.53	7.56	7.83	---
	13	4.95	6.53	13.14	9.06	13.94	17.38	15.00	---	---	25.05	10.76	12.61	---
	14	4.44	4.96	11.30	9.97	17.66	14.74	15.01	---	---	24.00	15.28	12.62	---
	15	4.12	5.17	9.66	.37	3.34	7.80	13.36	---	---	3.34	10.71	10.98	---
	16	5.25	5.77	8.15	2.38	7.62	10.26	12.38	---	---	3.42	8.68	9.47	---
	17	6.47	7.26	9.30	3.33	6.99	10.96	13.61	---	---	3.84	10.70	12.55	---
	18	3.61	4.91	9.32	.16	13.37	13.37	10.45	---	---	18.67	17.34	8.07	---
	19	4.39	5.44	10.19	2.32	4.65	9.40	5.17	---	---	14.43	9.92	10.45	---
	20	3.14	5.23	10.24	.64	4.18	2.63	12.1	---	---	20.58	18.20	9.72	---
	21	4.00	5.31	12.45	.49	2.71	2.20	12.98	---	---	15.10	10.33	4.53	---
	22	3.49	5.32	11.40	1.46	2.46	1.96	11.93	---	---	15.11	9.81	3.24	---
	23	2.67	5.00	11.87	.91	2.67	1.90	11.87	---	---	15.32	10.02	3.70	---
	24	4.76	5.28	12.68	9.24	7.92	3.98	8.18	---	---	23.80	12.68	7.92	---
	25	3.00	5.08	10.63	6.66	6.13	2.48	11.95	---	---	32.55	20.43	13.01	---
	26	4.61	6.71	14.66	13.07	19.69	2.80	12.80	---	---	15.45	10.15	4.35	---
	27	4.22	6.32	8.43	10.02	15.85	10.81	11.34	---	---	18.76	15.05	12.40	---
	28	7.16	8.22	11.33	14.04	17.22	11.66	12.72	---	---	13.25	11.93	7.43	---
	29	5.42	7.80	8.32	9.91	11.24	9.91	12.03	---	---	27.63	17.33	17.86	---
	30	7.55	9.14	9.93	8.08	3.87	6.23	9.14	---	---	4.65	7.02	8.34	---
	31	7.07	7.60	8.65	6.80	7.07	11.56	7.07	---	---	18.98	16.07	9.98	---
	32	5.21	6.00	7.05	6.00	5.47	8.90	4.42	---	---	14.73	12.87	7.05	---
	33	7.27	7.53	7.80	7.80	7.27	11.24	14.15	---	---	24.47	14.95	16.54	---
	34	7.52	7.52	8.84	8.05	8.05	9.37	11.22	---	---	15.47	13.35	14.14	---
	35	6.60	5.81	6.60	6.33	6.33	8.18	7.32	---	---	10.56	17.45	7.32	---

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

FRONT WALL CENTERLINE TUBE RATES

TC #		2	4	6	8	13	38	51	61	63
ELEVATION		110'-6"	106'-6"	88'-6"	74'-6"	60'-6"	50'-7"	43'-11"	35'-7"	25'-7"
TEST	1	6.44	7.40	11.34	18.08	10.33	----	10.13	3.04	2.52
	2	6.78	8.89	14.72	16.31	11.01	---	8.80	2.88	2.36
	3	5.18	4.36	7.55	8.08	8.61	---	13.11	4.66	1.33
	4	10.11	11.36	7.36	24.67	9.84	---	14.62	4.05	3.01
	5	11.16	9.57	10.37	24.92	10.10	---	19.11	12.75	7.45
	6	18.33	12.60	18.68	27.14	12.86	---	20.28	13.39	4.57
	7	9.26	8.47	10.44	10.85	6.35	---	23.56	18.55	9.53
	8	10.92	7.48	10.66	22.31	16.76	---	7.22	15.70	9.60
	9	13.67	9.36	10.48	25.83	14.20	---	7.05	17.38	7.84
	10	11.48	4.61	15.38	14.92	7.24	---	5.40	15.72	5.66
	11	5.21	4.35	6.79	6.53	4.95	---	7.85	6.26	6.26
	12	5.46	5.72	6.77	6.25	5.46	---	8.88	8.09	7.66
	13	12.88	6.26	7.84	11.56	6.79	---	7.58	14.47	5.21
	14	10.77	4.96	8.39	11.56	5.48	---	12.36	14.74	5.22
	15	8.07	5.17	14.16	11.77	2.57	---	2.32	18.13	6.22
	16	7.62	5.77	10.79	15.83	4.46	---	2.32	15.83	7.62
	17	8.05	6.99	12.29	14.41	5.68	---	4.63	16.26	9.37
	18	8.07	5.17	14.16	11.25	7.28	---	10.19	9.92	6.49
	19	9.13	4.91	12.84	6.22	8.86	---	9.66	10.98	5.44
	20	8.66	9.98	11.30	22.69	9.08	---	9.19	16.07	4.97
	21	10.33	11.34	17.22	21.98	8.48	---	3.23	5.58	3.48
	22	10.34	10.07	18.29	15.90	4.80	---	2.21	4.80	2.45
	23	10.02	7.64	16.91	19.02	13.46	---	2.40	5.00	2.67
	24	10.56	8.18	9.51	15.07	6.34	---	16.40	12.95	5.02
	25	10.10	8.24	6.86	15.66	10.10	---	19.64	20.43	9.57
	26	12.27	10.58	19.96	19.96	7.51	---	12.80	5.40	4.35
	27	9.22	7.64	14.26	8.16	7.11	---	8.69	14.26	3.44
	28	9.54	9.81	12.99	12.19	9.54	---	6.11	8.75	6.90
	29	9.91	8.06	11.24	10.18	10.44	---	18.92	20.77	9.38
	30	9.66	9.66	13.38	25.81	13.90	---	8.61	8.87	7.55
	31	7.86	8.12	11.56	8.12	7.60	---	7.33	11.56	8.12
	32	6.00	5.21	8.10	6.26	5.21	---	5.21	7.84	5.73
	33	8.85	7.00	7.00	18.66	6.48	---	21.57	19.98	12.56
	34	8.31	6.90	6.29	10.36	5.68	---	22.08	14.94	10.43
	35	7.12	5.81	5.54	7.39	3.20	---	7.72	8.18	7.65

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

		Right Wall Horizontal Average Tube Rates			Rear Wall Horizontal Average Tube Rates	Left Wall Horizontal Average Tube Rates	Front Wall Horizontal Average Tube Rates		
TC #		17-21	42-46	55-59	23-29	30-34	10-16	35-41	48-54
Elevation		69'-8"	59'-7"	49'-11"	59'-7"	59'-7"	69'-6"	59'-7"	49'-11"
TEST	1	8.65	9.54	8.28	5.78	11.67	11.94	10.31	8.24
	2	9.53	9.16	5.82	4.87	12.23	10.34	11.11	6.92
	3	7.07	9.27	9.58	4.79	10.72	8.56	8.85	11.57
	4	13.51	11.84	7.90	6.01	10.20	13.20	15.68	9.39
	5	5.67	9.98	10.64	12.22	17.10	16.33	17.34	18.73
	6	14.40	15.11	16.75	8.07	14.53	17.01	17.41	12.26
	7	7.84	11.96	18.26	8.21	9.04	10.90	16.12	17.13
	8	3.66	7.63	7.10	9.22	14.12	13.80	20.10	20.73
	9	7.38	10.05	6.53	14.01	14.83	16.45	18.43	17.94
	10	8.20	16.31	15.28	12.13	19.48	14.92	18.98	13.85
	11	4.84	5.09	9.18	9.10	4.79	6.35	7.59	7.76
	12	5.62	5.46	9.16	8.74	6.19	5.72	6.38	8.75
	13	10.18	14.34	15.70	13.34	16.06	12.93	17.64	13.27
	14	8.34	15.34	17.92	14.06	16.81	13.91	18.09	13.66
	15	9.70	11.38	9.41	10.62	18.29	10.77	15.70	8.54
	16	11.70	10.93	12.13	10.46	18.37	12.74	15.45	9.09
	17	13.77	10.44	11.95	10.44	16.47	13.17	16.88	10.35
	18	7.31	12.77	16.73	6.07	14.48	10.81	17.16	16.12
	19	6.96	4.61	8.72	7.52	7.50	9.70	14.43	9.54
	20	2.89	9.52	13.62	6.42	7.77	10.92	16.25	9.16
	21	2.76	10.14	13.51	5.51	13.72	15.85	18.76	8.42
	22	2.52	9.36	13.43	6.28	14.85	13.48	17.66	7.74
	23	3.19	10.16	13.64	6.04	15.54	19.17	17.12	12.28
	24	12.22	12.22	8.55	9.74	15.86	11.89	16.08	9.18
	25	9.63	14.00	22.35	9.61	14.18	12.04	16.76	13.81
	26	10.54	12.21	10.25	7.53	14.45	14.22	13.95	10.17
	27	10.81	12.40	14.70	8.14	13.52	9.88	10.03	8.88
	28	12.94	14.44	12.81	9.21	17.60	13.52	14.80	7.26
	29	11.34	16.07	20.06	12.18	12.72	12.30	16.76	17.63
	30	9.52	10.66	4.48	12.01	11.47	14.00	16.51	10.51
	31	7.71	10.38	17.84	10.85	8.85	7.33	16.78	9.14
	32	6.32	7.98	14.02	8.53	9.02	5.21	14.51	8.11
	33	10.08	17.06	18.21	10.44	10.66	8.33	16.05	16.05
	34	8.21	14.67	13.35	9.11	9.27	8.10	13.79	16.57
	35	7.65	10.75	10.12	9.05	9.50	7.75	9.20	9.42

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

BASELINE TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	I	1	199.2937	199.1341	.1596	3.1643	
		2	201.3871	201.2135	.1736	3.4418	
		3	198.3883	198.2384	.1499	2.9719	2.9392
		4	195.8045	195.6946	.1099	2.1789	
2	A	1	199.1977	199.0534	.1443	2.8609	
		2	199.6807	199.5009	.1798	3.5647	
		3	202.8649	202.7226	.1423	2.8213	2.8088
		4	202.3445	202.2442	.1003	1.9885	
3	E	1	199.0122	198.8632	.1490	2.9541	
		2	202.2508	202.1171	.1337	2.6507	
		3	201.9826	201.8976	.0850	1.6852	2.13475
		4	199.6584	199.5954	.0630	1.249	
4	E	1	202.5778	202.5080	.0698	1.3838	
		2	200.8579	200.7484	.1095	2.1769	
		3	202.7075	202.5924	.1151	2.282	1.91965
		4	197.7676	197.6750	.0926	1.8359	
5	K	1	199.5913	---	---	---	
		2	197.4684	197.2730	.1954	3.874	
		3	194.9513	194.7783	.1730	3.4299	3.38826
		4	202.0694	201.9251	.1443	2.8609	

Avg. Wt. Loss/Test 2.6381 MG/CM^2

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

BIASED FIRING TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	B	1	197.9531	197.6484	.3047	6.0411	
		2	202.1660	201.8659	.3001	5.9499	5.8795
		3	198.3393	198.0383	.3010	5.9678	
		4	200.5603	200.2799	.2804	5.5593	
2	Q	1	199.3158	199.1437	.1721	3.4121	
		2	196.2751	196.0480	.2271	4.5026	4.3777
		3	202.8709	202.5541	.3168	6.2810	
		4	200.2327	200.0655	.1672	3.3150	
3	R	1	198.8940	198.7626	.1314	2.6051	
		2	199.8790	199.6842	.1948	3.8622	3.4081
		3	196.0683	195.8721	.1962	3.8899	
		4	199.3342	199.1690	.1652	3.2753	
4	M	1	199.5078	199.3628	.1450	2.8748	
		2	198.7039	198.4853	.2186	4.3341	3.8201
		3	198.3125	198.1121	.2004	3.9732	
		4	200.8838	200.6771	.2067	4.0981	
5	D	1	197.9655	197.7001	.2654	5.2619	
		2	202.9412	202.5809	.3603	7.1435	5.7289
		3	199.1306	198.7976	.3330	6.6022	
		4	198.2205	198.0234	.1971	3.9078	

Avg. Wt. Loss/Test 4.6429 MG/CM^2

WATERWALL CORROSION COUPON

DATA SUMMARY

WEIGHT LOSS EVALUATION

OVERFIRE AIR TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	S	1	200.7678	200.5465	.2213	4.3876	
		2	196.0684	195.8121	.2563	5.0815	4.5244
		3	199.6433	199.3849	.2584	5.1235	
		4	197.8187	197.6419	.1768	3.5053	
2	T	1	200.7026	199.1437	.2802	5.5554	
		2	---	---	---	3.3540	3.9044
		3	593.7075	593.2000	.5075	3.3540	
		4	---	---	---	3.3540	
3	F	1	199.1897	198.9156	.2741	5.4344	
		2	199.4476	199.1351	.3125	6.1958	6.0401
		3	199.3119	198.9858	.3261	6.4654	
		4	199.0463	198.7404	.3059	6.0649	
4	N	1	202.2354	202.6125	.2234	4.4292	
		2	201.2249	200.9784	.2465	4.8872	3.7656
		3	---	---	---	2.8729	
		4	397.4898	397.2000	.2898	2.8729	
5	2	1	---	---	---	---	
		2	191.8528	191.6484	.2044	4.0525	3.9752
		3	192.7875	192.5909	.1966	3.8979	
		4	---	---	---	---	

Avg. Wt. Loss/Test 4.4419 MG/CM^2

TEST DATA SUMMARY
BARRY NO. 4

Test No.	1	2	3	4	5	6	7	8	9	10	11	12	13
Date (1/84)	1/20	1/21	1/21	1/21	1/23	1/23	1/23	1/23	1/24	1/24	1/24	1/24	1/19
Time	1630	0900	1300	1700	1038	1313	1413	1610	1245	1337	1440	1604	0930
Test Conditions													
Load	MWG	240	240	240	204	240	238	194	194	200	237	311	308	305
Main Steam Flow	10^6 lb/hr	1700	1700	1700	1500	1700	1680	1364	1369	1410	1667	2139	2118	2075
Coal Feed Rate	10^3 lb/hr	90	90	90	81	91	94	77	81	79	96	96	97	95
Main Steam Pressure	psig	2400	2400	2400	2400	2400	2398	2401	2403	2400	2398	2404	2404	2409
Hot RH Pressure	psig	530	530	530	530	530	524	507	510	496	501	504	510	503	505
Feedwater Temperature	°F	450	450	450	450	450	447	440	439	439	439	439	439	439	439
Excess Air at Inlet	%	19.1	20.8	19.1	19.8	20.8	20.8	17.5	15.1	5.7	10.1	8.0	8.0	14.7	16.6
Mill Temperature Differential	°F	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Damper Tilt	deg.	0	0	0	+15	+15	0	0	+1	-20	0	-30	-30	0	0
Mills in Service		A	A	A	A	A	A	A	A	A	A	A	A	A	A
# 1 Coal Burner		A	A	A	A	A	A	A	A	A	A	A	A	A	A
		A	A	A	A	A	A	C	C	C	C	C	C	C	A
		A	A	A	A	A	A	A	A	A	A	A	A	A	A
	Bottom	A	A	A	A	A	A	A	A	A	A	A	A	A	A
Air Compensated Flame Volume, % Vol.															
Air Nozzles (Center Side Wall)		100	100	100	100	100	100	100	100	100	100	100	100	100	100
All Dampers		100	100	100	100	100	100	100	100	100	100	100	100	100	100
Theoretical Air for Combustion	lb/hr	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Emissions (Corr. to 3% O2, Dry Basis)															
NO	ppm	730	810	870	860	880	880	730	780	900	944	938	940	906	891
NO2	ppm	1000	1070	1150	1060	1060	1060	970	1034	1161	1037	1009	1044	1040	1018
CO	ppm	0	110	90	110	70	70	70	100	110	110	110	110	74	90
SO2	lb/10^6 Btu	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76
O2	lb/10^6 Btu	5.73	5.90	5.90	5.90	5.90	5.90	5.67	5.74	5.94	5.94	5.94	5.94	5.74	5.74
Heat Losses															
L1 (dry gas)	%	5.37	5.96	5.78	5.70	5.81	5.78	5.40	5.44	4.93	5.00	5.16	4.96	5.66
L2 (wet gas)	%	11.29	11.33	11.34	10.96	11.5	11.55	10.15	10.3	10.1	10.8	14.5	13.3	10.48

* Balance Coal - A
Intermediate Coal - C Mill Only - B
Powder Coal - D
Combination Coals - A, B, C, D, M & O

TEST DATA SUMMARY
BARRY NO. 4

ACCELERATED CORROSION RATE DATA

ALABAMA POWER, BARRY NO. 4

Firing Condition	Corrosion Rate*, Mils/Yr
Baseline	34
	24
Baseline	17
	18
Baseline	11
	13
Baseline	16
	16
Low NO_x	32
	26
Low NO_x	41
	52
Low NO_x	77
	87
Low NO_x	13
	18

* Paired corrosion rate values obtained on two coupons exposed on the same probe.

TYPICAL COAL ANALYSIS

ALABAMA COAL

Obtained From
Peabody Coal Company
Analysis by Pittsburg Testing Laboratory

Proximate Analysis As Received

SAMPLE IDENTIFICATION Date	ABC 9/30/72	PEABODY WARRIOR 9/14/72	PEABODY TIGER 9/30/72
Moisture - %	8.40	10.1	9.2
Ash - %	13.00	11.36	9.4
Volatile Matter - %	25.92	19.75	28.8
Fixed Carbon - %	52.68	58.79	52.6
Sulfur - %	2.02	2.67	2.55
HHV - BTU/LB	1[illegible],897	12,131	12,269

Ultimate As Fired

Date	1/07/72
Moisture - %	9.09
Carbon - %	70.01
Hydrogen - %	3.83
Oxygen - %	3.83
Nitrogen - %	1.28
Sulfur - %	2.21
Ash - %	9.75
HHV - BTU/LB	12,290

MIDWEST BITUMINOUS

Analysis By Alabama Power Co.

Proximate Analysis As Received

SAMPLE IDENTIFICATION Date	EAGLE 1 11/72	EAGLE 2 11/72
Moisture - %	8.63	10.36
Ash - %	9.75	8.86
Volatile Matter - %	----	----
Fixed Carbon - %	----	----
Sulfur - %	2.75	3.15
HHV - BTU/LB	13,072	13,023

PETROLEUM COKE

Analysis by Gulf Oil Company, Port Arthur, Texas

Proximate Analysis As Received

SAMPLE IDENTIFICATION	A2602
Date	2/17/70
Moisture - %	7.7
Ash - %	.10
Volatile Matter - %	10.80
Fixed Carbon - %	81.40
Sulfur - %	3.53
HHV - BTU/LB	15,700

REFERENCES

1. Blakeslee, C. E. and Selker, A. P.,"Program For Reduction of NO_x From Tangential Coal Fired Boilers - Phase I"
2. Crawford, A. P., Manny, E. H. and Bartok, W., "Field Testing: Application of Combustion Modifications to Control NO_x Emissions From Utility Boilers"

APPENDIX I
COMPFLOW - WINDBOX
COMPARTMENT AIR FLOW DISTRIBUTION COMPUTER PROGRAM

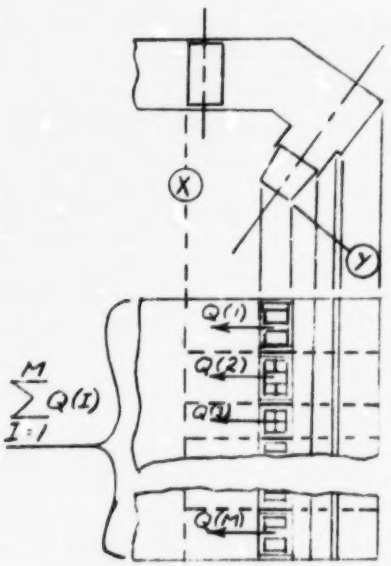
INTRODUCTION

A description of COMPAIR, a computer program which calculates the windbox assembly air flow distribution, was presented in Reference 1. The program has been subsequently found to be deficient; the approach taken in the calculation of the compartment loss coefficient resulted in operational difficulties in certain cases. The program was revised to eliminate this problem.

The revised program, COMPFLOW, is described herein. The basic assumptions and limitations of the calculation method are outlined and discussed. Program runs for two tests conducted at Barry #2 are included.

ANALYSIS

Consideration will be initially focused on those cases where the air flow to each compartment is supplied solely by the windbox.



Assumptions:

1. Constant total pressure at compartment inlet plane, i.e., P_{T_X} = const.
2. Constant density, i.e., R(I) = R = const.
3. Constant static pressure at nozzle exit plane, i.e., P_{s_y} = const.
4. Fully turbulent flow, i.e., Head Loss $\approx$ (Velocity)^2.

Utilizing these assumptions, it follows that

$$2 * \left[\frac{P_{T_X} - P_{s_y}}{R}\right] = K(I) * \left[\frac{Q(I)}{A(I)}\right]^2 = \text{const.} \quad \text{-----------(1)}$$

Where K(I) = loss coef. for Compartment "I"
Q(I) = volume rate of flow for Compartment "I"
A(I) = nozzle exit area of Compartment "I"

Equation (1) yields

$$\frac{Q(I)}{\sum_{I=1}^{M} Q(I)} = \frac{A(I)/\sqrt{K(I)}}{\sum_{I=1}^{M} A(I)/\sqrt{K(I)}} \quad \text{----------(2)}$$

By definition

$$P_{T_y}(I) = P_{s_y} + \frac{R}{2} * \left[\frac{Q(I)}{A(I)}\right]^2 \quad \text{----------(3)}$$

Using Equations (1) and (3), we have

$$2 * \left[\frac{P_{T_X} - P_{T_y}(I)}{R}\right] = 2 * \left[\frac{P_{T_X} - P_{s_y}}{R}\right] - \left[\frac{Q(I)}{A(I)}\right]^2 = [K(I) - 1] *$$

$$\left[\frac{Q(I)}{A(I)}\right]^2 \quad \text{----------(4)}$$

In order to arrive at a relation for K(I), the windbox compartment total pressure loss will be set equal to the sum of its component losses, i.e.,

$$2 * \left[\frac{P_{T_X} - P_{T_y}(I)}{R}\right] = [K_D(I) + K_\beta(I) + K_{90}(I) + K_f(I)] * \left[\frac{Q(I)}{B(I)}\right]^2 +$$

$$K_N(I) * \left[\frac{Q(I)}{A(I)}\right]^2 \quad \text{----------(5)}$$

Where B(I) = inlet flow area of Compartment "I"

Assumption (5): The values listed below, which allow for no interaction, adequately represent the compartment total pressure loss.

LOSS	VALUE	COMMENT	REFERENCE
Miter bend, $K_\beta(I)$	0.3	Typical, $\beta = 45°$	2
90° bend, $K_{90}(I)$	1.2	-----	2
Friction, $K_f(I)$	0.1	$f \approx 0.02$, $\frac{L}{D} \leq 5$; $K_f = f\frac{L}{D}$	2
Nozzle, $K_N(I)$	0	$K_N = \frac{1}{C_V} - 1$; Assume $C_v = 1$	3
Damper, $K_D(I)$	Figure 1	Assumed to include inlet loss	4

Using the above values, Equations (4) and (5) yield

$$K(I) = 1 + [1.6 + K_D(I)] * \left[\frac{A(I)}{B(I)}\right]^2 \quad \text{----------(6)}$$

For coal fired units the mill air must be taken into account. Using Equation (2) for the secondary air flow, it follows that

$$\frac{W(I)}{W1 + W2} = \frac{\left[\frac{A(I)/\sqrt{K(I)}}{\sum_{I=1}^{M} A(I)/\sqrt{K(I)}}\right] * W1 + X(I) * W2}{W1 + W2} \qquad \text{----------(7)}$$

where W(I) = mass rate of flow to Compartment "I"
W1 = total windbox air to corner
W2 = total mill air to corner
X(I) = fraction of mill air to Compartment "I"

Figure 1 and Equations (6) and (7) constitute the basis of COMPFLOW.

Note that if some other source of air were available to the windbox assembly, Equation (7) would yield the flow distribution with adjustments in the definitions of W2 and X(I).

Note also that if there is no corner to corner biasing of compartment dampers, Equation (7) may, to a very good approximation, be regarded on a furnace/elevation basis.

PROGRAM DESCRIPTION

A description of the program input is as follows:

Input

Fuel and Air Compartment Geometry

Number of Compartments
Width of Compartments
Height of Individual Compartments
Number of Dampers per Compartment
Nozzle Exit Area per Compartment

Test Data

Percent Excess Air
Total Air Flow
Compartment Damper Positions
Fuel Elevations in Service

Typical program outputs for Alabama Power Co., Barry #2, tests 5 and 20, are shown on Figure 2. These runs represent both normal and overfire air operation. A definition of the output is shown on Figure 3.

DISCUSSION

A. Development of the Method

The method presented herein, of calculating the windbox assembly flow

distribution, is the result of what is obviously a greatly simplified treatment; numerous assumptions were made in the development of the method. The validity of each of these assumptions will now be examined.

Assumption (1): Constant total pressure at the compartment inlet plane.

Air issuing from a duct branches to each of the windbox assemblies; the fluid is moving at a low velocity relative to that at the nozzle exit. It would be reasonable to assume that the total pressure loss between the supply duct exit and the compartment inlet plane is a negligible fraction of the velocity head at the nozzle exit. It is all the more realistic to assume, as is the case herein, that the total pressure distribution in the supply duct and the consequent losses along individual streamlines, are such that the total pressure is uniform at the compartment inlet plane.

Assumption (2): Constant density fluid within the windbox assembly.

The reasoning for this assumption is analagous to that set forth in (1); note that while isothermal flow is not implied between the supply duct and the compartment inlet, it is assumed within the windbox assembly.

Assumption (3): Constant static pressure at the nozzle exit plane.

The static pressure of the jets issuing from the windbox nozzles is equal to the local furnace pressure. The variation in furnace pressure throughout this region should be negligibly small.

Assumption (4): Fully turbulent flow.

This is a valid assumption for the vast majority of cases; unit Reynolds numbers(based on nozzle exit velocity) greater than 10^5 per foot are typical even for small opening of compartment dampers.

Assumption (5): The compartment loss coefficient for existing configurations are adequately represented by the formulations presented herein (i.e. Figure 1 and Equation (6)).

Curves of K versus damper position, as calculated from Figure 1 and Equation (6), are shown in Figure 4 for compartment outlet/inlet area ratios (i.e. A(I)/B(I) of 0.534, 0.322 and 0.136; these values cover the range of our existing compartments. Results obtained from the cold-flow model tests of Reference 5, at area ratios of 0.322 and 0.136, are also shown in this figure; the

test results are seen to be in excellent agreement with the predicted values. These test results indicate that nozzle tilt, flow rate, firing angle, the presence of turning vanes and probably compartment inlet interaction, are secondary influences on compartment pressure loss and consequently on compartment flow rate. These results justify the omission of these factors in the development of the method presented herein.

B. Previous Calculations

In the previous method of calculating the windbox assembly flow distribution (Reference 1), the compartment loss coefficient was determined from the equation

$$K(I) = KO + K_D(I) * \left[\frac{A(I)}{B(I)}\right]^2$$

where $K_D(I)$ was specified as herein KO evaluated from test values of the total secondary air flow and windbox/furnace ΔP. Highly closed damper positions result in a very large value of K_D, as is seen in Figure 1, and a small error in this parameter will result in a large variation in KO. Program runs with all compartment dampers at or near the full open position yielded values of KO consistent with the value presented herein, i.e.,

@ 100% open, $K_D \approx 0.1$, $K = K/100\%$

from Equation (6), $K/100\% \approx 1 + 1.7 * \left[\frac{A}{B}\right]^2$

for existing geometries, $0 < \left[\frac{A}{B}\right]^2 < 0.29$

therefore, with $KO \approx K/100\%$, $1 < KO < 1.5$

Program runs with one or more compartment dampers highly closed would sometimes yield values of KO outside this range; in rare cases this would result in operational difficulties.

REFERENCES

1. N. D. Brown, "COMPAIR, Burner-Compartment Air-Flow Distribution Computer Program," Project No. 121029, September, 1971.

2. "Flow of Fluids Through Valves, Fittings, and Pipe," Crane Co., Technical Paper No. 409, May, 1942.

3. R. V. Giles, "Fluid Mechanics and Hydraulics," Schaum Publishing Co., 1962.

4. P. S. Dickey & H. L. Coplan, "A Study of Damper Characteristics," Trans. of the ASME, February, 1942.

5. N. D. Brown, "Windbox Compartment Flow Tests," Test Report 72-6, Project No. 412003, March 2, 1972.

DAMPER LOSS COEFFICIENT VS. POSITION

$$K_D = \frac{2(P_{T_1} - P_{T_2})/R}{(Q/A)^2}$$

P_{T_1} = Total Pressure @ "1"

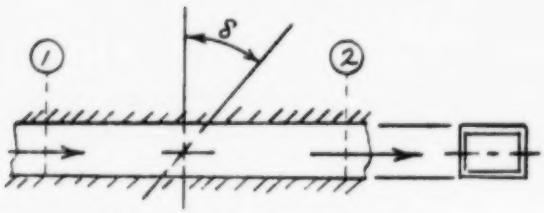
P_{T_2} = Total Pressure @ "2"

R = Fluid Density

Q = Volume Rate of Flow

A = Flow Area

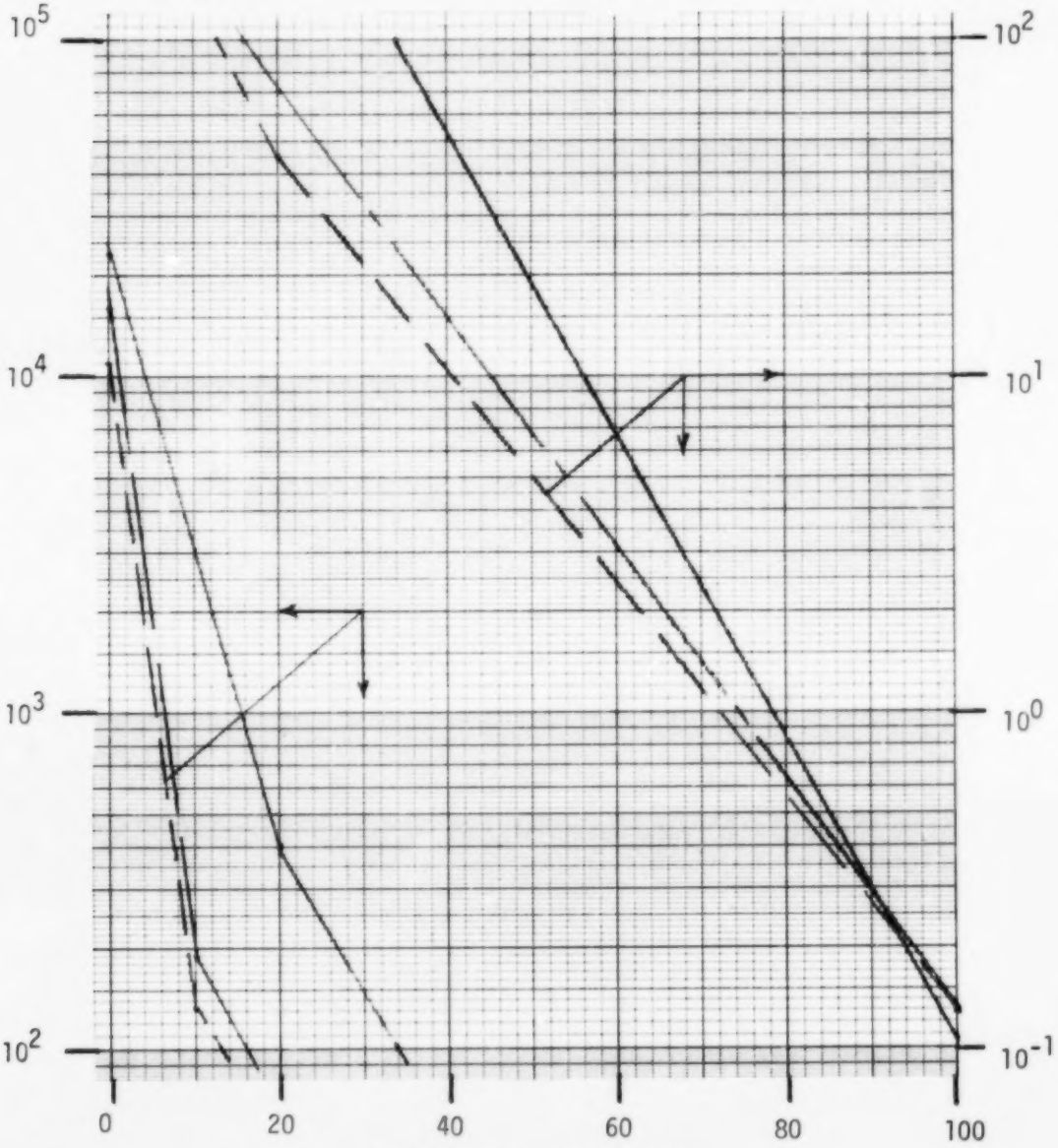
% Open = $(\delta/90) \times 100$



1 Blade

2 Blades

3 Blades



AIR FLOW DISTRIBUTION TO WINDBOX COMPARTMENTS
ALABAMA POWER AND LIGHT CO., BARRY #2
EPA '73 - '74 TESTS

FLOW DISTRIBUTION FOR TEST NO. 5

PER CENT EXCESS AIR 22.7

COMPARTMENT (NO.)	FIRING	AREA WT. FLOW (% OF TOTAL)	DAMPERS (% OPEN)	ACTUAL FLOW (% OF TOTAL)
1		9.44	60	7.8
2	Yes	6.55	20	8.39
3		18.03	100	16.37
4	Yes	6.55	20	8.39
5		9.44	100	8.64
6		9.44	100	8.64
7	Yes	6.55	20	8.39
8		18.03	100	16.37
9	Yes	6.55	20	8.39
10		9.44	100	8.64

Firing Fuel Compartment Total Air Flow (%) = 33.55
Air Flow Above Burner Zone (%) = 3.9
Air Flow to Burner Zone (% of Theor. Air) = 117.91

FLOW DISTRIBUTION FOR TEST NO. 20

PERCENT EXCESS AIR 24.2

COMPARTMENT (NO.)	FIRING	AREA WT. FLOW (% OF TOTAL)	DAMPERS (% OPEN)	ACTUAL FLOW (% OF TOTAL)
1		9.44	100	9.42
2		6.55	100	6.85
3		18.03	50	14.93
4	Yes	6.55	30	10.27
5		9.44	50	7.68
6		9.44	50	7.68
7	Yes	6.55	30	10.27
8		18.03	50	14.93
9	Yes	6.55	30	10.27
10		9.44	50	7.68

Firing Fuel Compartment Total Air Flow (%) = 30.82
Air Flow Above Burner Zone (%) = 23.73
Air Flow to Burner Zone (% of Theor. Air) = 94.72

COMPFLOW

Definition of Output

1. The "AREA WT. FLOW" is the ratio of the compartment free area to the total free area of the corner; as such it is a realistic approximation of the actual compartment (secondary) flow only when all compartment dampers are full open.

2. The comparment "ACTUAL FLOW" is the ratio of the compartment mass flow rate (including mill air if applicable) to the total mass flow to the corner (see ANALYSIS, equation (7)).

3. The "FIRING FUEL COMPARTMENT TOTAL AIR FLOW" is the ratio of the total mass flow rate to firing fuel compartments (including mill air if applicable) to the total mass flow to the corner.

4. The "AIR FLOW ABOVE BURNER ZONE" is defined as the percentage of the total mass flow rate supplied above the uppermost firing fuel compartment, less 50% of the flow to the compartment immediately above it.

5. % Theoretical Air to Burner Zone. $= \left(1 - \frac{\%\ \text{Air Above Burner Zone}}{100}\right)(100 + \%\ \text{Excess Air})$

COMPARTMENT LOSS COEFFICIENT
VS.
DAMPER POSITION

$$K = \frac{2(P_{T_x} - P_{s_y})/R}{(Q/A)^2}$$

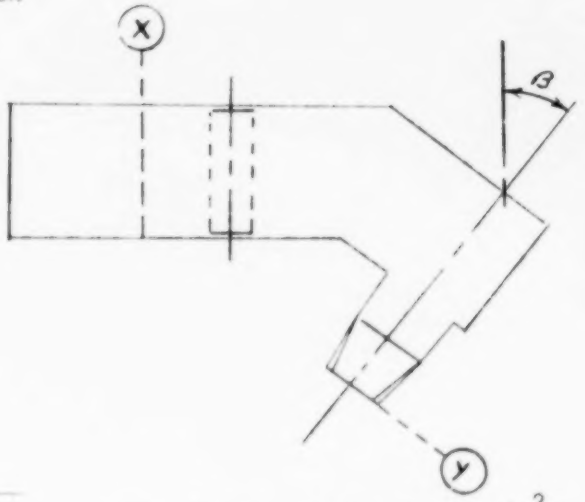
P_{T_x} = Total Pressure @ "x"

P_{s_y} = Static Pressure @ "y"

R = Fluid Density

Q = Volume Rate of Flow

A = Nozzle Exit Area



$\frac{A}{B} = 0.534 = \frac{\text{Nozzle Exit Area}}{\text{Compart. Inlet Area}}$

$K = 1 + (1.6 + K_D) \times (\frac{A}{B})^2$

LEGEND	
SYMBOL	A/B
○	0.322
□	0.136